SPECIFIED GAS EMITTERS REGULATION

QUANTIFICATION PROTOCOL FOR ENGINE FUEL MANAGEMENT AND VENT GAS CAPTURE PROJECTS

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Version 1.0

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All Quantification Protocols approved under the *Specified Gas Emitters Regulation* are subject to periodic review as deemed necessary by the Department, and will be re-examined at a minimum of every 5 years from the original publication date to ensure methodologies and science continue to reflect best-available knowledge and best practices. This 5-year review will not impact the credit duration stream of projects that have been initiated under previous versions of the protocol. Any updates to protocols occurring as a result of the 5-year and/or other reviews will apply at the end of the first credit duration period for applicable project extensions.

Any comments, questions, or suggestions regarding the content of this document may be directed to:

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Note to Project Developers

The protocol quantifies GHG emission reductions from two related activities: the improvement in the fuel efficiency of natural gas combustion engines and the capture of gases (primarily methane) normally vented to the atmosphere. The quantification approaches for both components are based on measurement and monitoring and thus provide a high level of accuracy. It is recognized that this approach for the fuel efficiency component in this protocol creates significant data collection / data management burdens on the part of the project developer. However, the approaches outlined in this protocol are intended to allow for the measurement of fuel efficiency gains from any natural gas combustion engine to account for site specific air-fuel ratio set points, loads, engine speeds and variable operating and maintenance practices. This generalized approach is designed to be broadly applicable to any natural gas combustion engine regardless of site to site and engine to engine differences.

Additionally, consultation with industry experts during the development of this protocol identified that at the time of protocol writing, a technically sufficient data set reflecting the fuel consumption of the current fleet of natural gas combustion engines in Alberta was not available. The data availability has been historically limited due to the fact that manufacturer's fuel consumption data generally does not match actual field operational data and many operating engines do not have their own distinct fuel meters. Therefore, the approach outlined in this protocol was developed to allow for the quantification of fuel savings from the implementation of an engine fuel management system on any type of natural gas combustion engine in a technically robust way to allow for the collection of representative field data that can be used for more accurate generalizations of fuel savings among different classes of engines at a later time using the flexibility mechanism outlined in this protocol.

It is anticipated that once a significant amount of data has been collected on the fuel consumption of the various makes and models of natural gas combustion engines in the Alberta fleet operating under normal Alberta conditions, it will then be possible to utilize a less burdensome and more generalized approach to GHG quantification for the fuel efficiency component of this protocol that is sufficiently conservative, as outlined in the Flexibility Mechanisms of the protocol (See Appendix A). At that time it will be possible for existing projects installed before the publication of this protocol to quantify offsets from fuel efficiency gains using this protocol.

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1.0 PROJECT AND METHODOLOGY SCOPE AND DESCRIPTION

This quantification protocol is written for those familiar with the operation of natural gas combustion engines and control systems that manage the fuel consumption for these engines. Some familiarity with, or general understanding of the operation of these practices and processes is expected.

The opportunity for generating carbon offsets with this protocol arises from the direct and indirect reductions of greenhouse gas (GHG) emissions resulting from the implementation of engine management systems that control engine air-fuel ratios to improve fuel use efficiency and from the implementation of vent gas capture systems that prevent the venting of greenhouse gases to the atmosphere. These types of projects will include the implementation of a new engine control system that allows an engine to operate at a different range of air fuel ratios from that of the original engine design, which in turn can result in a reduction in fuel consumption. This may include the establishment of a lean burn combustion condition within an engine previously designed to be operated under rich burn conditions. Additionally, projects may implement vent gas capture systems to capture and combust vented gases in the engine to displace the primary fuel source. These process changes may be designed for retrofits or for new installations and may impact engine fuel consumption and the vent gas emissions associated with the operation of the engine and other nearby facility equipment.

1.1 Protocol Scope and Description

This protocol does not prescribe the configuration or nature of the process changes, but instead serves as a generic 'recipe' for project developers to follow in order to meet the measurement, monitoring and GHG quantification requirements. **FIGURE 1.1** offers a process flow diagram for a typical project. The engine fuel management system may be applied in conjunction with a vent gas capture system or without.

It should be noted that while this protocol is targeted at projects that involve the implementation of engine control systems for natural gas combustion engines, some procedures in this protocol may be transferable to other types of engine management systems. However, there could be considerable differences between these types of systems (e.g. engine control systems installed on engines that combust liquid fuels versus gaseous fuels), which could lead to inaccuracy in the quantification of the GHG emission reductions.

Protocol Approach:
The protocol approach to quantifying the GHG reductions from the implementation of an engine management system is discussed below and the approach for projects that implement vent gas capture systems is discussed separately in the following section. The baseline condition for this protocol is defined as the GHG emissions from the fuel consumption of the unit under its original configuration prior to the installation of the new engine control system, and where applicable, the continued venting of gases containing methane to the atmosphere. **FIGURE 1.2** offers a process flow diagram for a typical baseline scenario.

The fuel consumption of an internal combustion engine at a particular air/fuel ratio will depend on the engine load and engine speed (RPM), in addition to site-specific factors such as altitude, ambient temperature, maintenance cycles and the age and condition of the equipment. At present, the industry standard in Alberta is to present fuel consumption in terms of the brake specific fuel consumption (BSFC), which is defined as the rate of fuel energy flow into an engine divided by the mechanical power produced by the engine[1]. The mechanical power is required for loads such as gas compressors, pumps, electrical generators and other devices. The mechanical power from the engine equals the power required by the load[2]. The use of BSFC allows the performance of an engine to be expressed in a way that is independent of engine type and size since it accounts for the power output and the energy content of the fuel[3]. A lower BSFC indicates better engine efficiency. Engine performance is commonly presented as a load map showing the fuel consumption of the engine (in BTU/hour or kJ/hour) at various loads (in BHP or BkW) at specific engine speeds (RPMs).

In this protocol the baseline is site specific and the fuel consumption of the engine is established relative to a specific engine make, model, air/fuel ratio and configuration prior to any modifications. As such, the approach used in this protocol to determine engine fuel gas savings relies on direct measurement of various parameters in order to determine the brake specific fuel consumption of the original un-modified engine at several different set points and then to subsequently perform the same set of measurements at the same set points for the modified engine. These before and after measurements are herein referred to as 'Pre-Audits' and 'Post-Audits' in this document. The use of direct measurements before and after the modification of the engine was selected in order to ensure applicability of this protocol to any natural gas combustion engine regardless of engine to engine and site to site differences. Field fuel consumption results may vary between seemingly identical models due to subtle mechanical design differences and load variables[4].

Additionally, there currently exists very little reliable data to support accurate engine fuel savings from the implementation of engine management systems on different types of engines. Engine manufacturer data sets were not suitable for use under the baseline condition as these data represent the engine's lowest achievable fuel consumption determined under ideal conditions in the laboratory and typically underestimate fuel consumption in the field[5].

Due to the different characteristics of the sites where natural gas combustion engines may operate in Alberta, the protocol provides a simple and an advanced method to determine the fuel gas savings from the implementation of an engine management system.

Advanced Approach: The advanced method requires the measurement of BSFC at three different loads and three different RPMs per load in order to develop complete load maps pre and post installation. This approach is applicable to sites where the load can be varied without causing

[1] Canadian Association of Petroleum Producers (CAPP) Fuel Gas Best Management Practices: Efficient Use of Fuel Gas in Engines. May 2008.
[2] Ibid.
[3] Ibid.
[4] Ibid.
[5] Ibid

negative impacts to upstream or downstream operations. This approach also gives the most complete characterization of an engine's fuel consumption at different loads and RPMs and therefore is applicable to the full spectrum of operating loads provided that the initial Pre and Post-Audit measurements span at least 25% of the rated load range.

Simple Approach: The simple method requires the measurement of BSFC at one load and three RPMs in order to characterize the fuel consumption at the current operating conditions before and after the engine modification. This 'snap-shot' approach is applicable to sites that maintain fairly consistent loadings or sites that are/were unable to vary the engine load in order to develop a full load map at the time of the Pre and Post-Audits without causing upsets to upstream or downstream operations. Therefore, this approach is only valid for moderate changes in load that are less than 25% different from the % rated load at the Pre and Post-Audit conditions. A load change of more than 5% of the engine's rated load as compared to the Pre and Post-Audit set point would require the use of the fuel efficiency normalization approach described in Appendix C-1.

*For those installations completed before the publication of this protocol or sites where it was not possible to measure the BSFC of the original unmodified engine, a Flexibility Mechanism is provided in Appendix A to allow for the quantification of fuel gas savings in a conservative manner utilizing data from at least 5 other engines of the same make and classification[6] operating with the same type of engine management systems in the project condition. Additionally, project proponents applying the flexibility mechanism would have to ensure in the Pre-Audits of the 5 unmodified engines that the air fuel ratio of each engine is documented following the guidelines in Appendix C and that the baseline air fuel ratios are all within the same range (i.e. +/- 5 to 10%) such that fuel consumption will be consistent across the set.

**For engines that operate at constant speeds (e.g. to drive a generator) the simple and advanced approaches would only require measurements at one RPM per load.

Both the simple and advanced approaches require the project proponent to track the RPM and engine loads on a monthly basis after the initial Pre and Post-Audits to account for any changes in operation from the initial set points.

Once the BSFC values have been determined for the same set points for the un-modified engine and again for the modified engine it is possible to determine the fractional change in fuel consumption at the specific engine RPMs and loads due to the installation of the engine management system. The fractional change in fuel consumption (at a specific RPM and engine loading) is defined to be the difference in Pre and Post-Audit BSFC values divided by the Post-Audit BSFC. The fractional fuel savings at the Pre and Post-Audit set points then provide the basis for the calculation of the actual fuel savings in the project condition as the actual operating conditions will differ from the set points. The procedure to complete Pre and Post-Audits for the determination of the fractional change in fuel consumption of the engine is discussed in detail in Appendix C.

[6] Example engine classifications are provided in Table 2.1 (page 8) of the CAPP Fuel Gas Best Management Practices (May 2008) and in Appendix C-1 of this document.

In the project condition the fuel consumption of the engine is directly metered. As such, emission reductions are determined from the multiplication of the metered fuel consumption in the project condition times the average change in fuel consumption (at the specific RPM and load) each month times the carbon emission factor for the fuel gas.

The baseline condition for projects that install vent gas capture systems either independently or in conjunction with engine fuel management systems is the atmospheric release of the metered quantity of vent gases captured and combusted in the project condition based on the composition of the vent gases (% methane and carbon content). The GHG reductions from vent gas capture are quantified using mass and energy balances to determine the quantity of methane normally emitted to atmosphere.

Protocol Applicability:
To demonstrate that a project meets the requirements under this protocol, the project developer must provide evidence that:

1. The determination of brake specific fuel consumption and fractional change in fuel consumption for the quantification of the baseline engine fuel consumption (B4 Unit Operation) has been completed according to the guidelines discussed in Appendix C. During the completion of Pre and Post-Audits to measure the fractional change in fuel consumption the project proponent must note any changes made to the engine or the equipment that is powered by the engine (e.g. compressor) that could impact the measured BSFC. These changes could include the addition / removal of equipment or other modifications made to the engine or the prime mover that could impact the load on the engine (i.e. reduced frictional load through compressor retrofits etc.). Project proponents would have to demonstrate that these changes have not impacted the validity of the fuel savings calculated from measured data during the Pre and Post-Audits.
2. The engine modification must not impair the functionality of the unit, process or overall facility such that additional energy inputs are required as demonstrated by facility process flow diagrams and/or unit operational performance data. Unit operational data may include engine operating hours, records of down time or other records to demonstrate that the engine fuel management system and/or the combustion of captured vent gases does not de-rate the engine or cause a significant increase in down time (and potentially increase compressor start gas emissions). The project proponent would need to show that the use of other units (engines) and/or supplemental fuels is not needed to compensate for increased parasitic loads, reduced fuel energy content and/or decreased engine power output. Functional equivalence may be demonstrated through an affirmation from the project developer or other qualified third party;
3. There must not be any regulations requiring the capture and destruction or conservation of vent gas emissions from the processes and/or units impacted by the project activity that have been quantified in the baseline as vented GHG emissions under SS B5b Venting of Emissions Captured in the Project. Project proponents should refer to the November 16, 2006 version of the Alberta Energy and Resources Conservation Board (ERCB) Directive 60

(D60) Upstream Petroleum Industry Flaring, Incineration and Venting for further guidance on restrictions on flaring and venting of solution gas and other types of vent gases. D60 provides sector specific performance standards for flaring and venting that must be met by operators as well as decision trees to evaluate whether gas can be economically conserved[7] instead of vented or flared. Conservation opportunities are evaluated as economic or uneconomic based on the criteria listed in Section 2.8 of D60[8]. It should be noted that D60 does not prescribe any one particular conservation option and the use of solution gas for supplemental fuel could be compared to re-injection of the solution gas for reservoir pressure maintenance as a conservation option, each with significantly different GHG implications.

4. **The engine management system implemented as a result of the protocol must comply with all other air emissions regulations in Alberta, particularly NOx requirements.**

   The following guidelines are intended to assist project proponents in evaluating whether their project activity of capturing a vent gas stream may be considered to be surplus to regulation, but should in no way be seen as an exhaustive list of requirements or a replacement for the guidance in D60 and other regulations enforced by the ERCB or Alberta Environment.

   a. If the ERCB determines that an individual source of vent gas has sufficient flow rate to sustain stable combustion and must be flared according to D60 Section 8.1, then the project proponent will not be eligible for offsets from venting in the baseline under SS B5b.

   b. If a project is not covered under criteria 3.a) but involves the recovery and use of solution gas at levels exceeding the 900 m^3/day threshold specified in Section 2.3 of D60 and is also deemed to be economic to implement one or more conservation activities as specified in Section 2.8 of D60, then the project may not be eligible for offsets from venting under SS B5b. If the captured volume of solution gas cannot sustain stable combustion and is less than the threshold or deemed to be uneconomic to conserve then the project activity may be eligible for offsets from venting.

   c. As stated in Section 8.3 of D60, if the total facility benzene emission limits specified in Directive 039 Revised Program to Reduce Benzene Emissions from Glycol Dehydrators are exceeded at the project site then venting may not be permitted and the project may not be eligible for offsets from venting in the baseline under SS B5b.

5. For projects where the combustion of vent gases is required under D60 (or other applicable regulation) or where the baseline practice already involved the flaring or incineration of the waste gas stream, then the baseline condition is the flaring of the waste gas stream. The

[7] In Directive 60 conservation is defined as the recovery of solution gas for sale, for use as fuel for production facilities, for other useful purposes (e.g., power generation), or for beneficial injection into an oil or gas pool (e.g., pressure maintenance, enhanced oil recovery).

[8] Solution gas conservation activities must be evaluated in terms of an economic analysis as discussed in Section 2.8 of D60, where an activity is deemed to be economic if it has a net present value of greater than -$50,000 CDN.

project proponent can claim offsets following the Flexibility Mechanism in Appendix A, to quantify GHG reductions from reduced fuel gas consumption for flaring and engine operation. The project proponent must demonstrate that the re-direction of the waste gases to the engine actually results in reduced flare fuel usage as evidenced by metered volumes of waste gas sent to flare/incinerator and/or volumes of supplemental fuel consumed or through engineering designs for the flare/incinerator unit;

6. The boundary of the project activity must not include the quantification of baseline GHG emissions from engine fuel combustion and vent gas emissions that are subject to regulation under the Alberta Specified Gas Emitter Regulation.
7. The quantification of reductions achieved by the project is based on actual measurement and monitoring (except where indicated in this protocol) as indicated by the proper application of this protocol; and,
8. The project must meet the requirements for offset eligibility as specified in the applicable regulation and guidance documents for the Alberta Offset System. [Of particular note:
    a. [The date of equipment installation, operating parameter changes or process reconfiguration are initiated or have effect on the project on or after January 1, 2002 as indicated by facility records;]
    b. [The project may generate emission reduction offsets for a period of 8 years unless an extension is granted by Alberta Environment, as indicated by facility and offset system records. Additional credit duration periods require a reassessment of the baseline condition; and,]
    c. [Ownership of the emission reduction offsets must be established as indicated by facility records.]

FIGURE 1.1: Process Flow Diagram for Project Condition

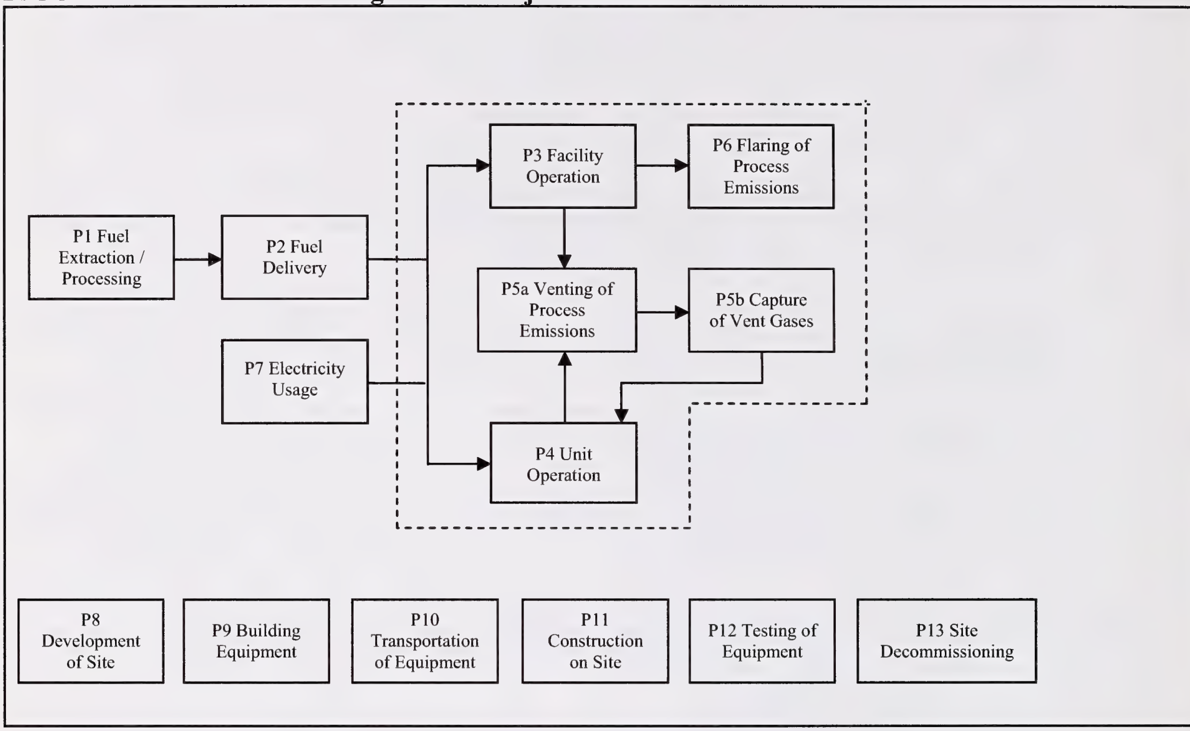
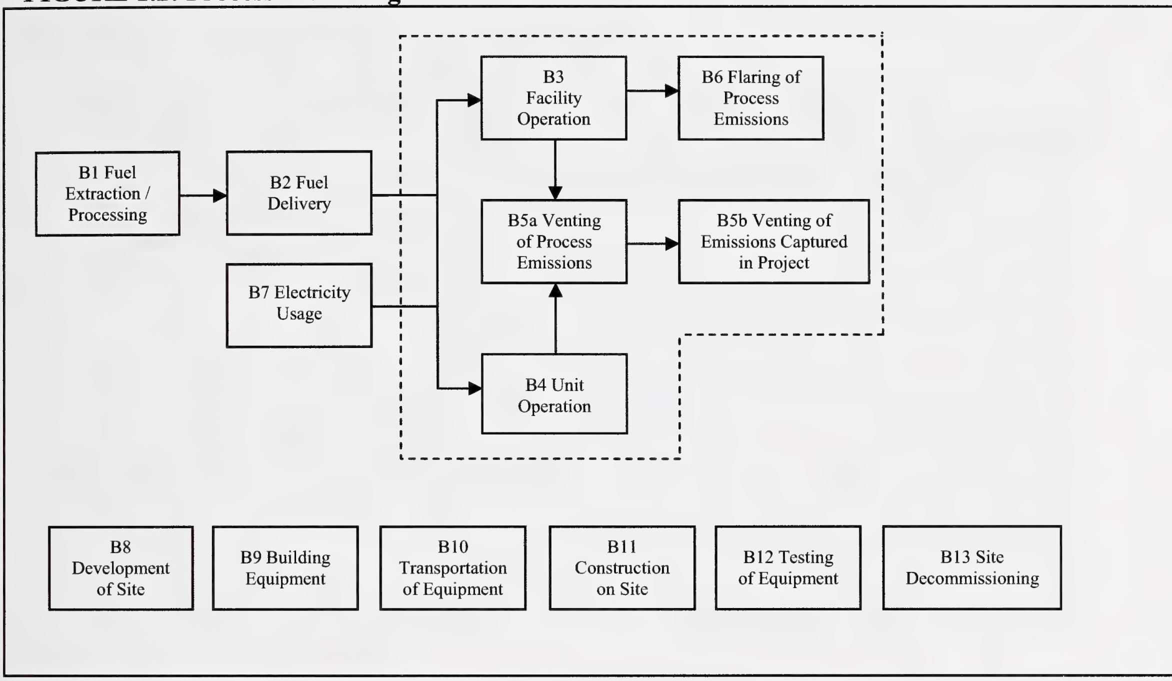


FIGURE 1.2: Process Flow Diagram for Baseline Condition



Protocol Flexibility:
Flexibility in applying the quantification protocol is provided to project developers in the following ways:

1. In project configurations where there is a change in the quantity of waste gases or process emissions flared as a result of the project activity the project proponent may use the Flexibility Mechanism in Appendix A to quantify associated GHG emissions. This situation could occur when the baseline practice was the flaring of waste gas streams and the project condition involves re-directing the waste gas stream for use as supplemental fuel to reduce the fuel requirements for operating the flare. Alternatively, the project condition could also involve an increase in flaring whereby some gas streams previously vented to atmosphere are re-directed to flare in the project condition;

2. For project scenarios where it is not possible to measure the brake specific fuel consumption before and after the installation of a new engine management system the project proponent may use fractional fuel savings data from other engines of the same make and classification. The project proponent should apply the protocol flexibility mechanism under the SS “B4 Unit Operation” to ensure that the estimation of the baseline fuel consumption is overly conservative across the full spectrum of engine speeds and loads. The use of this approach is contingent on there being sufficient data from at least 5 similar engines of the same make and classification operating with the same type of engine management system. For further details, refer to Appendix A.

3. Engine fuel management systems and vent gas capture systems can be installed on a single engine or on multiple units at multiple sites. As such, the protocol allows for flexibility in quantifying offsets from multiple installations;

4. For projects that install engine management systems onto engines that operate at constant speed to drive generators or other equipment, the Simple and Advanced approaches may be altered to include measurement at one RPM for each load, rather than normal three RPMs per load; and

5. Site specific emission factors may be substituted for the generic emission factors indicated in this protocol document. The methodology for generation of these emission factors must be sufficiently robust to ensure accuracy. In particular, project proponents that conduct site specific engine exhaust gas emission testing may develop dynamic emission factors for use under SS “B4 Unit Operation” such that the project and baseline conditions have distinct emission factors for methane and nitrous oxide. The development of these emission factors must follow the US Environmental Protection Agency (EPA) 40 CFR Part 60 Guidelines (i.e. Method 7E for NO_x and Methods 18 or 25A for methane). Exhaust gas analyses must be completed for each load and RPM set point during the Pre and Post-Audits to ensure that the baseline and project emission factors are representative of the full range of operating conditions for the original engine and the modified engine.

If applicable, the proponent must indicate and justify why flexibility provisions have been used.

1.2 Glossary of New Terms

Facility
The facility is defined as the collection of processes and units surrounding the project unit, but not including the Project Unit (e.g. an engine) itself. The greenhouse gas emissions from the facility are defined as remaining constant in cases where only the project unit is impacted by the project activity (e.g. implementation of an engine fuel management system without a vent gas capture system). Greenhouse gas emissions from the facility are defined as decreasing when vent gas capture systems are implemented as determined from metered data and facility process flow diagrams. Where the Project Unit encompasses the entire site, there will not be a source or sink for facility operations.

Project Unit
The project unit is defined as the equipment that is retrofitted with the expectation that the fuel consumption will change. All other related processes, excluding the unit, are covered under the heading of facility operation. The project unit is typically a natural gas combustion engine.

Engine Management System
An engine management system is a broad term used in this protocol to describe a process control system used to control the air flow and fuel flow into an engine to better manage the power demands placed on the engine and improve operation. The engine management system may also include features to assist in engine starting, ignition control, knock control, coolant temperature control as well as safety shutdown features.

Air/Fuel Ratio
The air/fuel ratio for an internal combustion engine refers to the ratio of air to fuel that is fed into the combustion chamber of an engine. When the air to fuel ratio is exactly in line with the combustion reaction chemistry (the stoichiometry of the reaction), the air/fuel ratio is called "Stoichiometric." This means that the chemically correct quantity of air is present in the combustion chamber during combustion (i.e. perfect combustion resulting in the production of only carbon dioxide and water vapour).

In cases where excess air is fed to a combustion chamber, the ratio is termed "lean" and when excess fuel is added the ratio is termed "rich." Typically engines operating under lean-burn conditions have better fuel economy,

	while engines operating under rich-burn conditions have more power and are easier to operate, but conversely have lower fuel efficiency.
Vent Gases	Gases that are vented to the atmosphere, typically during natural gas extraction, processing and transmission activities. Vent Gases will typically consist of compressor rod-packing gas or instrument gas that is designed to be vented to allow for safe operation of equipment. Additional sources of vent gases may include gases vented from flash tanks and glycol dehydrator re-boilers.
Brake Specific Fuel Consumption	The BSFC is the ratio between the rate at which fuel energy is supplied to an engine divided by the mechanical power, brake horsepower (BHP) or brake kilowatts (BkW), available for the engine load. Typical units of measure are BTU/BHP-h and kJ/BkW-h.

2.0 QUANTIFICATION DEVELOPMENT AND JUSTIFICATION

The following sections outline the quantification development and justification.

2.1 Identification of Sources and Sinks (SS's) for the Project

SS's were identified for the project by reviewing relevant process flow diagrams pertaining to the operation of natural gas combustion engines. This process confirmed that the SS's in the process flow diagrams covered the full scope of eligible project activities under the protocol.

Based on the process flow diagrams provided in **FIGURE 1.1**, the project SS's were organized into life cycle categories in **FIGURE 2.1**. Descriptions of each of the SS's and their classification as controlled, related or affected are provided in **TABLE 2.1.**

FIGURE 2.1: Project Element Life Cycle Chart

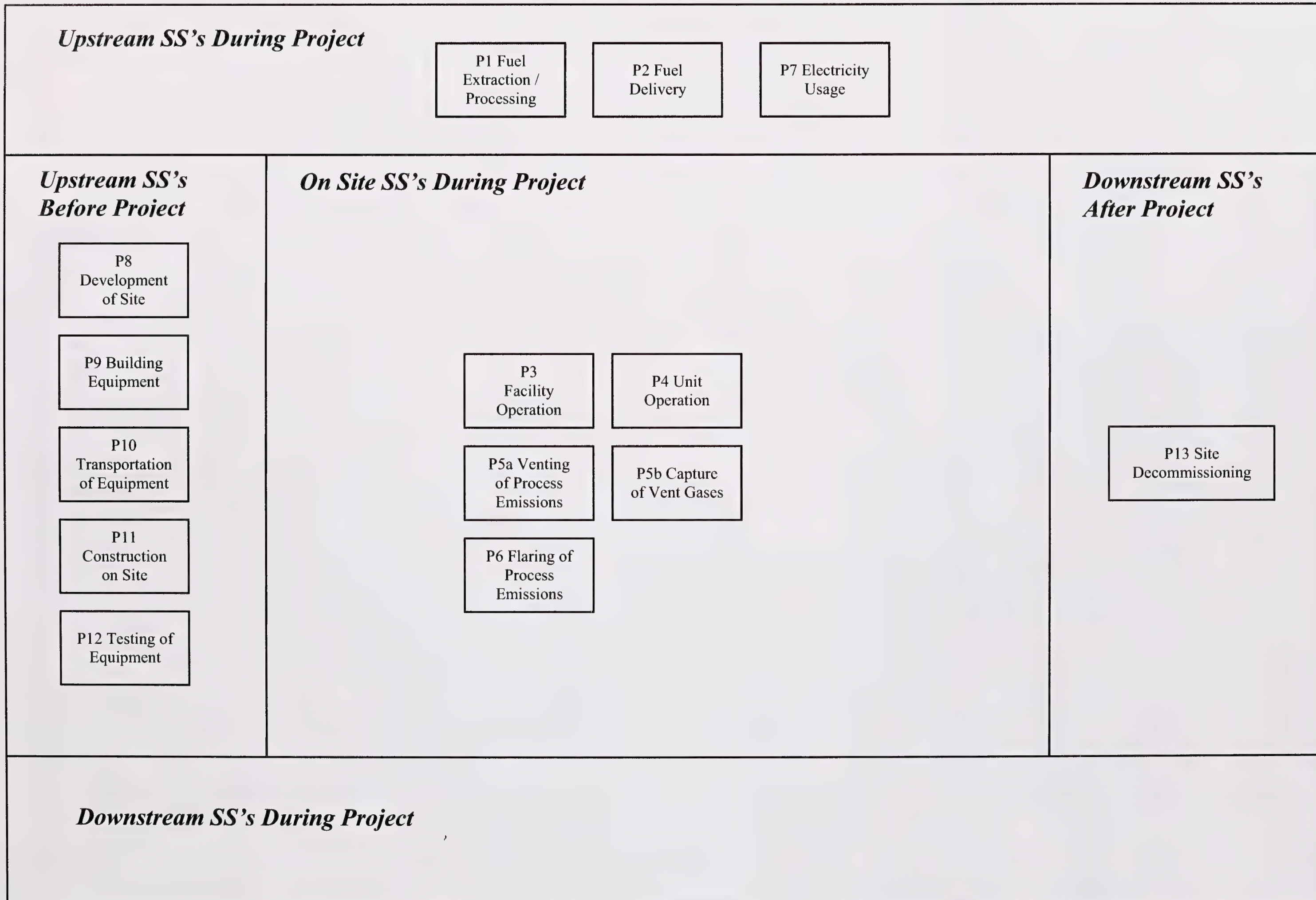


TABLE 2.1: Project SS's

1. SS	2. Description	3. Controlled, Related or Affected
Upstream SS's during Project Operation		
P1 Fuel Extraction and Processing	Each of the fuels used throughout the project will need to sourced and processed. This will allow for the calculation of the greenhouse gas emissions from the various processes involved in the production, refinement and storage of the fuels. The total volumes of fuel for each of the SS's are considered under this SS. Volumes and types of fuels are the important characteristics to be tracked.	Related
P2 Fuel Delivery	Each of the fuels used throughout the project will need to be transported to the site. This may include shipments by tanker or by pipeline, resulting in the emissions of greenhouse gases. It is reasonable to exclude fuel sourced by taking equipment to an existing commercial fuelling station as the fuel used to take the equipment to the sites is captured under other SS's and there is no other delivery.	Related
P7 Electricity Usage	Electricity will be required at the project site for facility operations or for operation of the engine air/fuel control system and usage may change due to the implementation of the project activity. This power may be sourced either from internal generation, connected facilities or the local electricity grid. Metering of electricity may be netted in terms of the power going to and from the grid. Quantity and source of power are the important characteristics to be tracked as they directly relate to the quantity of greenhouse gas emissions.	Related
Onsite SS's during Project Operation		
P3 Facility Operation	Typical facilities could include natural gas processing, dehydration and transmission or other upstream oil and gas operations. The operations of the facility at the project site may require the combustion of fossil fuels, precipitating greenhouse gas emissions. Volumes and types of fuels are the important characteristics to be tracked.	Controlled
P4 Unit Operation	The operation of the unit would require the combustion of fossil fuels and this operation would be expected to change as a result of the implementation of the project activity. As such the volumes, compositions and energy contents of all fuels consumed would need to be tracked. The most likely project configuration would be the combustion of natural gas in an internal combustion engine. In the event that vent gas emissions are captured and fed back into the unit as supplemental fuel, the energy content, composition and volume of captured gases must also be tracked to quantify associated GHG emissions under the SS P5b Capture of Vent Gas Emissions.	Controlled
P5a Venting of Process Emissions	The operation of the unit and other equipment at the facility, such as gas compressors, dehydrators and flash tanks may result in the venting of methane and other hydrocarbon emissions to the atmosphere due to equipment leaks, engineered vents and equipment failure. Process emissions may also be vented during start-up, shut-down or intermittently during regular operation. Typical sources of vent gas emissions include vented instrument gas, tank vents, re-boiler vents, engine casing gas, compressor rod packing gas, compressor blow-downs, pressure relief valves, pneumatic valves and other equipment leaks.	Controlled

P5b Capture of Vent Gases	Vent gas emissions from the unit or other equipment at the facility may be captured and destroyed in order to minimize emissions and/or to recover the energy content of the escaping emissions. The energy content, flow rate and composition of the captured vent emissions must be tracked in the project activity.	Controlled
P6 Flaring of Process Emissions	The flaring of process emissions may occur in certain project configurations during upset conditions or during downtime. Flaring in the project condition may still constitute an emission reduction compared to the baseline activity, but should nonetheless be tracked if the project condition includes the utilization of process gas streams that were previously flared in the baseline or if the project condition involves incremental flaring of process emissions during upset conditions. Instances of flaring should be tracked in addition to the quantities of gas sent to flare and fuel used to supplement flaring. For projects that only capture vent gases not previously flared in the baseline and do not flare any vent gas streams in the project condition, this SS may be excluded.	Controlled
Downstream SS's during Project Operation		
Other		
P8 Development of Site	The site of the facility may need to be developed. This could include civil infrastructure such as access to electricity, gas and water supply, as well as sewer etc. This may also include clearing, grading, building access roads, etc. There will also need to be some building of structures for the facility such as storage areas, storm water drainage, offices, vent stacks, firefighting water storage lagoons, etc., as well as structures to enclose, support and house the equipment. Greenhouse gas emissions would be primarily attributed to the use of fossil fuels and electricity used to power equipment required to develop the site such as graders, backhoes, trenching machines, etc.	Related
P9 Building Equipment	Equipment may need to be built either on-site or off-site. This includes all of the components of the storage, handling, processing, combustion, air quality control, system control and safety systems. These may be sourced as pre-made standard equipment or custom built to specification. Greenhouse gas emissions would be primarily attributed to the use of fossil fuels and electricity used to power equipment for the extraction of the raw materials, processing, fabricating and assembly.	Related
P10 Transportation of Equipment	Equipment built off-site and the materials to build equipment on-site will all need to be delivered to the site. Transportation may be completed by truck, barge and/or train. Greenhouse gas emissions would be primarily attributed to the use of fossil fuels to power the equipment delivering the equipment to the site.	Related
P11 Construction on Site	The process of construction at the site will require a variety of heavy equipment, smaller power tools, cranes and generators. The operation of this equipment will have associated greenhouse gas emission from the use of fossil fuels and electricity.	Related
P12 Testing of Equipment	Equipment may need to be tested to ensure that it is operational. This may result in running the equipment using test anaerobic digestion fuels or fossil fuels in order to ensure that the equipment runs properly. These activities will result in greenhouse gas emissions associated with the combustion of fossil fuels and the use of electricity.	Related

P13 Site Decommissioning	Once the facility is no longer operational, the site may need to be decommissioned. This may involve the disassembly of the equipment, demolition of on-site structures, disposal of some materials, environmental restoration, re-grading, planting or seeding, and transportation of materials off-site. Greenhouse gas emissions would be primarily attributed to the use of fossil fuels and electricity used to power equipment required to decommission the site.	Related

2.2 Identification of Baseline

2.2.1 Identification and Assessment of Possible Baseline Scenarios

An assessment of potential baseline scenarios was conducted based on the recommended methodology from best practice guidance in the Alberta Offset Credit Project Guidance Document. Potential baseline options were assessed based on their capacity to incorporate two aspects of the baseline: the GHG emissions from engine fuel consumption and the GHG emissions from venting of gases containing methane. As such, these two components of the baseline scenario are discussed in separate parts. Each baseline scenario also contemplated the selection of a static or dynamic approach or both. **TABLE 2.2** provides a summary of the baselines considered.

TABLE 2.2 Assessment of Possible Baseline Scenario

1. Baseline Options	2. Description	3. Static/ Dynamic	4. Accept or Reject and Justify
1.Historic Benchmark	A) Assessment of the baseline scenario based on site specific fossil fuel consumption data from the operation of the site for one or more years prior to installation of engine fuel management / vent gas capture systems.	Static.	Reject. The use of site specific historic data would not provide a high level of accuracy given that engine fuel consumption will vary depending on operating conditions including hours operational, RPM's, horsepower and loads. Further, it is not common practice for project proponents to directly meter fuel consumption for each unit / engine and data may not be available.
	B) Assessment of baseline scenario based on site specific venting emissions, determined from historic data from the site for one or more years prior to installation of vent gas capture systems.	Static.	Reject. Venting emissions are difficult to meter and metering is not common industry practice. Further many vent gas streams are small and intermittent emission sources and individually have limited value to warrant metering in the baseline.
2.Performance Standard	A) Assessment of the typical GHG emissions from the fuel consumption of 'typical' engine of a given make and model.	Dynamic or Static	Reject. The operational characteristics of the engine will vary depending on make / model, air fuel ratio setting, load demands, age and other characteristics at the site thereby rendering extrapolation over a range of operating conditions potentially imprecise.
	B) Assessment of the baseline scenario based on the typical composition and quantity of gases vented from compressor rod-packing gas, instrument gas, etc. during natural gas extraction, processing and transmission activities.	Dynamic or Static.	Reject. Detailed data on the venting of gases from each source would need to be obtained. This data may not accurately represent site venting emissions. Further, depending on the site this approach may lead to a significant over or under-estimate of venting emissions.
3.Comparison-Based	A) Assessment of baseline GHG emissions from the unit / engine based on the performance and fuel consumption from a control group.	Dynamic	Reject. This method is analytically and data intensive, and there is significant variation in fuel consumption between individual engines and at different sites and depending on a number of operating characteristics.

1. Baseline Options	2. Description	3. Static/ Dynamic	4. Accept or Reject and Justify
	B) Assessment of baseline GHG emissions from venting based on the quantity and composition of gases vented from a control group representative of typical industry practice.	Dynamic.	Reject. This approach is not practical as it would be necessary to characterize average industry emissions from venting to represent the 'control' group. Generalizing venting emissions by defining control groups would be challenging given that venting can vary significantly between sites and depending on the equipment and operations at each site.
4. Projection-Based	A) Assessment of the baseline GHG emissions from unit / engine operation using a model to project fuel consumption and the GHG intensity of unit operation into the future. This could include a projection of the GHG intensity based on past trends or expected future trends.	Dynamic	Accept. This approach is applicable for determining emissions from fuel consumption given that appropriate models exist to model the change in fuel consumption from the project to the baseline scenarios. Further, unlike the other baseline options this approach uses site-specific data of unit fuel consumption at different RPM's and loads obtained from direct measurement.
	B) Assessment of baseline GHG emissions from venting using a model to project the quantity and composition of gases vented into the future.	Dynamic.	Accept. This approach is applicable for quantifying the GHG emissions from vent gas capture given that the quantity and composition of gases captured and combusted in the project condition can be used to estimate emissions in the baseline. Further, unlike the other baseline options this approach is based on direct measurement of the characteristics of vent gases that would have been emitted in the absence of the project.
6.Other	A) Other quantification that may be applicable to the site-specific circumstances that can be justified with reasonable assurance.	Static or Dynamic.	Reject. Not Applicable. Project Specific.

2.2.2 Selection and Justification of Baseline Scenario

The development of quantification approaches for the implementation of engine fuel management and / or vent gas capture systems required the examination of a variety of baseline scenarios as described in Section 2.2.1. The main criteria used to evaluate each scenario included data availability, environmental integrity, accuracy, consistency with Alberta project configurations and ease of application (e.g. through monitoring requirements). The recommended baseline option for the protocol is the projection based approach for both the baseline avoided emissions from reduced engine fuel consumption and reduced venting.

The baseline condition for this protocol is defined as the fuel consumption of the unit under its original configuration prior to the installation of the new engine management system and/or the venting of gases containing methane to the atmosphere. The baseline is therefore site specific and depends on the operating characteristics and performance of the particular unit(s) and the type of engine management system being installed. The baseline fuel consumption would be

established relative to a specific engine make, model, air/fuel ratio setting and the load demands of the project site. The industry standard is to present this information as a ratio of the fuel energy flow rate into the engine to the brake power output of the engine, called the Brake Specific Fuel Consumption (BSFC).

In order to quantify the baseline GHG emissions, the project proponent will be responsible for taking measurements to determine the brake specific fuel consumption of the unmodified unit (operating at its original air-fuel ratio) at different set points (RPM and loads) during a Pre-Audit. The BSFC is then measured at the same set points after the installation of the engine management system (Post-Audit) to determine the fractional change in fuel consumption due to the project activity. The fractional change in fuel consumption represents the change in BSFC from Pre-Audit to Post-Audit divided by the BSFC at the Post-Audit (with each BSFC value measured at the same RPMs and loads).

Once the fractional change in fuel consumption has been established for a particular set point it is then possible to relate the actual monitored engine loadings and RPMs in the project condition to the fractional change in fuel consumption at the Pre and Post-Audit set points (refer to Appendices C and C-1). The monthly change in emission reductions from baseline to project are then calculated by multiplying the metered fuel consumption in the project condition times the fractional change in fuel consumption at the average load and RPM each month.

This quantification approach utilizes metered fuel consumption data per unit of brake power output (BSFC) to establish the fractional improvement in fuel consumption based on different engine operating parameters (loads and RPMs) and allows the project proponent to track what the baseline fuel consumption would have been had the new engine control system not been implemented. This approach ensures that the impacts of variable loads, engine speeds, maintenance practices and other engine or site specific conditions are captured to provide an accurate representation of the baseline fuel consumption for each installation.

The project proponent may choose between the 'Simple' approach (one load measurement and three RPM measurements at that load) and the 'Advanced' approach (measurements at three loads and three RPM measurements per load) approaches depending on the operating limitations of their specific site at the time of the Pre and Post-Audits. The project proponent should refer to Appendix C for further details on how to complete the Pre and Post-Audits and how to determine the fractional change in fuel consumption at different set points.

For projects that implement vent gas capture systems and combust the vent gases as supplemental fuel for operating the unit, the baseline emissions are determined from the measured quantity, composition and heating value of the vent gases captured and combusted in the project condition.

The approach to quantifying the baseline will be projection based as there are suitable models for the applicable baseline condition that can provide reasonable certainty. The baseline scenario for this protocol is dynamic as the emissions profile for the baseline activities would be expected to change materially relative to the defined unit and may fluctuate due to supply and demand dynamics, as well as other market conditions.

The baseline condition is defined, including the relevant SS's and processes, as shown in **FIGURE 1.2**. More detail on each of these SS's is provided in **Section 2.3**, below.

2.3 Identification of SS's for the Baseline

Based on the process flow diagrams provided in **FIGURE 1.2**, the project SS's were organized into life cycle categories in **FIGURE 2.2**. Descriptions of each of the SS's and their classification as either 'controlled', 'related' or 'affected' is provided in **TABLE 2.3.**

FIGURE 2.2: Baseline Element Life Cycle Chart

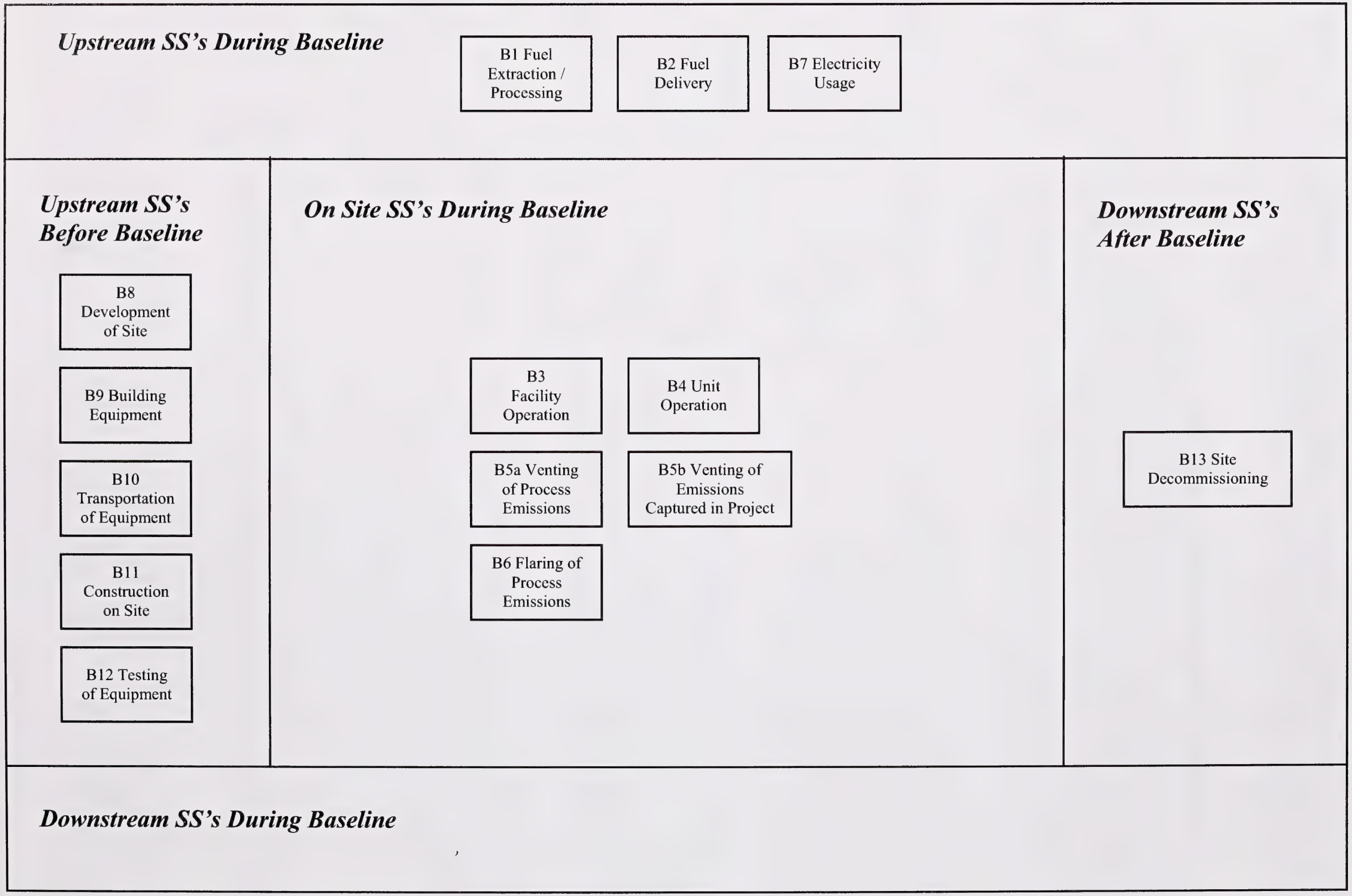


TABLE 2.3: Baseline SS's

1. SS	2. Description	3. Controlled, Related or Affected
Upstream SS's during Baseline Operation		
B1 Fuel Extraction and Processing	Each of the fuels used throughout the unit process will need to sourced and processed. This will allow for the calculation of the greenhouse gas emissions from the various processes involved in the production, refinement and storage of the fuels. The total volumes of fuel for each of the SS's are considered under this SS. Volumes and types of fuels are the important characteristics to be tracked.	Related
B2 Fuel Delivery	Each of the fuels used throughout the unit process will need to be transported to the site. This may include shipments by tanker or by pipeline, resulting in the emissions of greenhouse gases. It is reasonable to exclude fuel sourced by taking equipment to an existing commercial fuelling station as the fuel used to take the equipment to the sites is captured under other SS's and there is no other delivery.	Related
B7 Electricity Usage	Electricity will be required at the project site for facility operations and/or for operation of the unit in the baseline. This power may be sourced either from internal generation, connected facilities or the local electricity grid. Metering of electricity may be netted in terms of the power going to and from the grid. Quantity and source of power are the important characteristics to be tracked as they directly relate to the quantity of greenhouse gas emissions.	Related
Onsite SS's during Baseline Operation		
B3 Facility Operation	Typical facilities could include natural gas processing, dehydration and transmission facilities or other upstream oil and gas operations. The configuration of these processes may change as a result of the implementation of vent gas capture systems. The operations of the facility at the project site may require the combustion of fossil fuels precipitating greenhouse gas emissions. Volumes and types of fuels are the important characteristics to be tracked.	Controlled
B4 Unit Operation	The operation of the unit would require the combustion of fossil fuels and this operation would be expected to change as a result of the implementation of the project activity. As such the volumes and energy contents of all types of fuels consumed need to be tracked. The most likely project configuration would be the combustion of natural gas in a gas engine to provide energy for the compression of natural gas. The baseline fuel consumption rate of the unit would be determined through metered fuel consumption of the engine at different engine speeds and loads for the specific air-fuel ratio of the unit prior to the project activity. Refer to Appendix C for a detailed approach to determine the brake specific fuel consumption of an engine before and after the installation of an engine management system.	Controlled
B5a Venting of Process Emissions	The operation of the unit and other equipment at the facility, such as gas compressors, dehydrators and flash tanks may result in the venting of methane and other hydrocarbon emissions to the atmosphere due to equipment leaks, engineered vents and equipment failure. Process emissions may also be vented during start-up, shut-down or intermittently during regular operation. Typical sources of vent gas emissions include vented instrument gas, tank vents, re-boiler vents, engine casing gas, compressor rod packing gas, compressor blow-downs, pressure relief valves, pneumatic valves and other equipment leaks.	Controlled
B5b Venting of Emissions Captured in Project	Vent gases previously released due to the operation of the unit or other equipment at the facility may be captured and destroyed in the project condition in order to minimize emissions and/or to recover the energy content of the escaping emissions. The quantity of emissions that were previously vented in the	Controlled

	baseline condition is calculated based on measured data from the project condition. The volume or mass, energy content and composition of the captured vent gases must be tracked in the project activity as well as the quantities of any supplemental fossil fuels used to facilitate the capture and destruction of the vent gases.	
B6 Flaring of Process Emissions	In certain project configurations gas streams that were previously flared in the baseline may be re-directed to the project unit for use as supplemental fuel. The operation of a flare in the baseline may have required supplemental fossil fuels to ensure complete destruction of the waste gas stream(s) and therefore a reduction in flaring may reduce emissions from fuel usage. The important quantity to specify is the fuel usage per volume of waste gas flared based on metered data, gas heat values or flare specifications. The project proponent must demonstrate that the activity of re-directing the waste gas stream actually results in a reduction in flare fuel usage. For projects that only capture vent gases not previously flared in the baseline and do not flare any vent gas streams in the project condition, this SS may be excluded.	Controlled
Downstream SS's during Baseline Operation		
Other		
B8 Development of Site	The site of the facility may need to be developed. This could include civil infrastructure such as access to electricity, gas and water supply, as well as sewer etc. This may also include clearing, grading, building access roads, etc. There will also need to be some building of structures for the facility such as storage areas, storm water drainage, offices, vent stacks, firefighting water storage lagoons, etc., as well as structures to enclose, support and house the equipment. Greenhouse gas emissions would be primarily attributed to the use of fossil fuels and electricity used to power equipment required to develop the site such as graders, backhoes, trenching machines, etc.	Related
B9 Building Equipment	Equipment may need to be built either on-site or off-site. This includes all of the components of the storage, handling, processing, combustion, air quality control, system control and safety systems. These may be sourced as pre-made standard equipment or custom built to specification. Greenhouse gas emissions would be primarily attributed to the use of fossil fuels and electricity used to power equipment for the extraction of the raw materials, processing, fabricating and assembly.	Related
B10 Transportation of Equipment	Equipment built off-site and the materials to build equipment on-site will all need to be delivered to the site. Transportation may be completed by truck, barge and/or train. Greenhouse gas emissions would be primarily attributed to the use of fossil fuels to power the equipment delivering the equipment to the site.	Related
B11 Construction on Site	The process of construction at the site will require a variety of heavy equipment, smaller power tools, cranes and generators. The operation of this equipment will have associated greenhouse gas emission from the use of fossil fuels and electricity.	Related
B12 Testing of Equipment	Equipment may need to be tested to ensure that it is operational. This may result in running the equipment using test anaerobic digestion fuels or fossil fuels in order to ensure that the equipment runs properly. These activities will result in greenhouse gas emissions associated with the combustion of fossil fuels and the use of electricity.	Related

B13 Site Decommissioning	Once the facility is no longer operational, the site may need to be decommissioned. This may involve the disassembly of the equipment, demolition of on-site structures, disposal of some materials, environmental restoration, re-grading, planting or seeding, and transportation of materials off-site. Greenhouse gas emissions would be primarily attributed to the use of fossil fuels and electricity used to power equipment required to decommission the site.	Related

2.4 Selection of Relevant Project and Baseline SS's

Each of the SS's from the project and baseline condition were compared and evaluated as to their relevancy using the guidance provided in Annex VI of the "Guide to Quantification Methodologies and Protocols: Draft", dated March 2006 (Environment Canada). The justification for the exclusion or conditions upon which SS's may be excluded is provided in **TABLE 2.4** below. All other SS's listed previously are included.

TABLE 2.4: Comparison of SS's

1. Identified SS	2. Baseline (C, R, A)	3. Project (C, R, A)	4. Include or Exclude from Quantification	5. Justification for Exclusion
Upstream SS's				
P1 Fuel Extraction and Processing	N/A	Related	Include	N/A
B1 Fuel Extraction and Processing	Related	N/A	Include	
P2 Fuel Delivery	N/A	Related	Exclude	Excluded as the emissions from transportation are likely greater under the baseline condition.
B2 Fuel Delivery	Related	N/A	Exclude	
P7 Electricity Usage	N/A	Related	Exclude	Excluded due to functional equivalence as required by the Protocol Applicability Criteria in Section 1.
B7 Electricity Usage	Related	N/A	Exclude	
Onsite SS's				
P3 Facility Operation	N/A	Controlled	Exclude	Excluded due to functional equivalence between the baseline and project scenarios.
B4 Facility Operation	Controlled	N/A	Exclude	
P4 Unit Operation	N/A	Controlled	Include	N/A
B4 Unit Operation	Controlled	N/A	Include	
P5a Venting of Process Emissions	N/A	Controlled	Exclude	Excluded due to functional equivalence as process emissions not captured in the project activity would have been emitted under the baseline practice of venting these gases.
B5a Venting of Process Emissions	Controlled	N/A	Exclude	
P5b Capture of Vent Gases	N/A	Controlled	Include	N/A
B5b Venting of Emissions Captured in Project	Controlled	N/A	Include	
P6 Flaring of Process Emissions	N/A	Controlled	Exclude	Excluded as flaring will be functionally equivalent for the majority of project configurations. In cases where gas streams that were previously flared are now re-directed to the unit for use as supplemental fuel the project proponent should utilize the quantification procedures for the flexibility mechanism for flaring as per Appendix A.
B6 Flaring of Process Emissions	Controlled	N/A	Exclude	
Downstream SS's				

Other				
P8 Development of Site	N/A	Related	Exclude	Emissions from site development are not material given the long project life, and the minimal site development typically required.
B8 Development of Site	Related	N/A	Exclude	Emissions from site development are not material for the baseline condition given the minimal site development typically required.
P9 Building Equipment	N/A	Related	Exclude	Emissions from building equipment are not material given the long project life, and the minimal building equipment typically required.
B9 Building Equipment	Related	N/A	Exclude	Emissions from building equipment are not material for the baseline condition given the minimal building equipment typically required.
P10 Transportation of Equipment	N/A	Related	Exclude	Emissions from transportation of equipment are not material given the long project life, and the minimal transportation of equipment typically required.
B10 Transportation of Equipment	Related	N/A	Exclude	Emissions from transportation of equipment are not material for the baseline condition given the minimal transportation of equipment typically required.
P11 Construction on Site	N/A	Related	Exclude	Emissions from construction on site are not material given the long project life, and the minimal construction on site typically required.
B11 Construction on Site	Related	N/A	Exclude	Emissions from construction on site are not material for the baseline condition given the minimal construction on site typically required.
P12 Testing of Equipment	N/A	Related	Exclude	Emissions from testing of equipment are not material given the long project life, and the minimal testing of equipment typically required.
B12 Testing of Equipment	Related	N/A	Exclude	Emissions from testing of equipment are not material for the baseline condition given the minimal testing of equipment typically required.
P13 Site Decommissioning	N/A	Related	Exclude	Emissions from decommissioning are not material given the long project life, and the minimal decommissioning typically required.
B13 Site Decommissioning	Related	N/A	Exclude	Emissions from decommissioning are not material for the baseline condition given the minimal decommissioning typically required.

2.5 Quantification of Reductions, Removals and Reversals of Relevant SS's

2.5.1 Quantification Approaches

Quantification of the reductions, removals and reversals of relevant SS's for each of the greenhouse gases will be completed using the methodologies outlined in **TABLE 2.5**, below. It is important to note that the baseline SS's in **TABLE 2.5** are all quantified in terms of the change from the baseline to the project condition and therefore the project SS's are included under the baseline. A listing of relevant emission factors is provided in Appendix D. These calculation methodologies serve to complete the following three equations for calculating the emission reductions from the comparison of the baseline and project conditions.

$$\boxed{\text{Emission Reduction} = \text{Emissions}_{\text{Baseline}} - \text{Emissions}_{\text{Project}}}$$

$$\text{Emissions}_{\text{Baseline}} = \text{Emissions}_{\text{Fuel Extraction / Processing}} + \text{Emissions}_{\text{Unit Operation}} + \text{Emissions}_{\text{Venting of Emissions Captured in Project}}$$

$$\text{Emissions}_{\text{Project}} = \text{Emissions}_{\text{Fuel Extraction / Processing}} + \text{Emissions}_{\text{Unit Operation}} + \text{Emissions}_{\text{Capture of Vent Gases}}$$

Where:

$\text{Emissions}_{\text{Baseline}}$ = sum of the emissions under the baseline condition.

$\text{Emissions}_{\text{Fuel Extraction / Processing}}$ = emissions under SS B1 Fuel Extraction and Processing

$\text{Emissions}_{\text{Unit Operation}}$ = emissions under SS B4 Unit Operation

$\text{Emissions}_{\text{Venting of Emissions Captured in Project}}$ = emissions under SS B5b Venting of Emissions Captured in Project

$\text{Emissions}_{\text{Project}}$ = sum of the emissions under the project condition.

$\text{Emissions}_{\text{Fuel Extraction / Processing}}$ = emissions under SS P1 Fuel Extraction and Processing

$\text{Emissions}_{\text{Unit Operation}}$ = emissions under SS P4 Unit Operation

$\text{Emissions}_{\text{Capture of Vent Gases}}$ = emissions under SS P5b Capture of Vent Gases

TABLE 2.5: Quantification Procedures

1. Project / Baseline SS	2. Parameter / Variable	3. Unit	4. Measured / Estimated	5. Method	6. Frequency	7. Justify measurement or estimation and frequency
Project SS's						
P1 Fuel Extraction and Processing	This SS is quantified under Baseline SS B1 Fuel Extraction and Processing					
P4 Unit Operation	This SS is quantified under Baseline SS B4 Unit Operation					
P5b Capture of Vent Gases	This SS is quantified under Baseline SS B5b Venting of Emissions Captured in Project					
Baseline SS's						
B1 Fuel Extraction and Processing	$Emissions_{Fuel\ Extraction\ /\ Processing} = \sum (Vol.\ Fuel_i * EF\ Fuel_{i\ CO2})\ ;\ \sum (Vol.\ Fuel_i * EF\ Fuel_{i\ CH4})\ ;\ \sum (Vol.\ Fuel_i * EF\ Fuel_{i\ N2O})$					
	$Emissions_{Fuel\ Extraction\ /\ Processing}$	kg of CO_2e	N/A	N/A	N/A	Quantity being calculated based on fuel use under B4 Unit Operation.
	Volume of Natural Gas Combusted for B4 / $Vol.\ Fuel_i$	m^3	Measured	Direct metering of fuel consumption of unit. Note that this value is obtained from B4 and is equal to the metered fuel consumption in the project condition multiplied by the Fractional Change in fuel consumption from the baseline to the project.	Continuous metering.	Frequency of metering is highest level possible.
	CO_2 Emissions Factor for Natural Gas / $EF\ Fuel_{CO2}$	kg CO_2 per m^3	Estimated	From Environment Canada reference documents.	Annual	Reference values adjusted annually as part of Environment Canada reporting on Canada's emissions inventory.
	CH_4 Emissions Factor for Natural Gas / $EF\ Fuel_{CH4}$	kg CH_4 per L, m^3 or other	Estimated	From Environment Canada reference documents.	Annual	Reference values adjusted annually as part of Environment Canada reporting on Canada's emissions inventory.
	N_20 Emissions Factor for Natural Gas / $EF\ Fuel_{N2O}$	kg N_2O per L, m^3 or other	Estimated	From Environment Canada reference documents.	Annual	Reference values adjusted annually as part of Environment Canada reporting on Canada's emissions inventory.

B4 Unit Operation	*The following equation (1) should be used to calculate the total emissions from baseline Unit Operation for projects that implement air-fuel ratio controllers and DO NOT install vent gas capture systems. Note that this equation calculates the change in emissions from baseline to project.* 1. $\text{Emissions}_{\text{Unit Operation}} = \sum (\text{Fuel Consumption}_i * \text{Fractional Change}_{B\text{-}P} * \text{EF Fuel}_{CO2}); \sum (\text{Fuel Consumption}_i * \text{Fractional Change}_{B\text{-}P} * \text{EF Fuel}_{CH4}); \sum (\text{Fuel Consumption}_i * \text{Fractional Change}_{B\text{-}P} * \text{EF Fuel}_{N20})$ *The following equation (2) should be used to calculate the total emissions from Baseline Unit Operation for projects that implement vent gas capture systems (in addition to installing an engine management system) that provide supplemental fuel to the engine and displace a portion of the conventional fuel source. This equation also applies to project proponents that utilize the flexibility mechanism for projects that involved flaring of process emissions in the baseline. Note that this equation calculates the change in emissions from baseline to project.* 2. $\text{Emissions}_{\text{Unit Operation}} = \sum [(\text{Fuel Consumption}_i * \text{Fractional Change}_{B\text{-}P} + \text{Fuel Displaced}) * \text{EF Fuel}_{CO2}]; \sum [(\text{Fuel Consumption}_i * \text{Fractional Change}_{B\text{-}P} + \text{Fuel Displaced}) * \text{EF Fuel}_{CH4}); \sum [(\text{Fuel Consumption}_i * \text{Fractional Change}_{B\text{-}P} + \text{Fuel Displaced}) * \text{EF Fuel}_{N20})$ Where, $\text{Fuel Consumption}_i = \text{Mass}_{\text{FUEL GAS}} / \text{Density}_{\text{FUEL GAS}} + (\text{Mass}_{\text{VENT GAS}} / \text{Density}_{\text{VENT GAS}}) * [\text{LHV}_{\text{VENT GAS}} / \text{LHV}_{\text{FUEL GAS}}]$ $\text{Fuel Displaced} = (\text{Mass}_{\text{VENT GAS}} / \text{Density}_{\text{VENT GAS}}) * [\text{LHV}_{\text{VENT GAS}} / \text{LHV}_{\text{FUEL GAS}}]$					
	$\text{Emissions}_{\text{Unit Operation}}$	kg of CO_2 ; CH_4 ; N_2O	N/A	N/A	N/A	Quantity being calculated. Represents the summation of emissions calculated on a monthly basis.
	Total Fuel Consumption in Project Condition/ $\text{Fuel Consumption}_i$	m^3 of fuel (natural gas equivalent)	Measured	Calculated based on the continuous measurement of mass flow rate of fuel into the engine in the Project Condition. In project configurations where vent gases are captured and fed back into the engine for supplemental fuel, the total fuel consumption is the sum of the main fuel gas stream and the supplemental vent gas fuel, expressed as an energy equivalent quantity of the primary fuel (e.g. natural gas).	Continuous metering and monthly aggregation of values.	Frequency of metering is highest level possible. For the purposes of this protocol, continuous monitoring means collecting one data point at least every fifteen minutes.

	Fractional Change in Fuel Consumption from Baseline to Project Due to Implementation of an Air-Fuel Ratio Controller/ Fractional Change $_{B\text{-}P}$	-	Estimated	Fractional Change in fuel consumption from the baseline to the project condition is calculated based on measured BSFC values from pre and post installation, corrected for actual project loads and engine RPMs on a monthly basis. Fractional Change = (BSFC $_{Pre\text{-}Audit}$ – BSFC $_{Post\text{-}Audit}$)/ BSFC $_{Post\text{-}Audit}$. Refer to Appendix C for a step by step procedure to determine the fractional change in fuel consumption. Refer to Table C.3 in Appendix C (page 62) for a summary of monitoring requirements in the project condition.	BSFC values determined during Pre and Post-Audits and corrected with monthly average engine speeds and loads in the project condition	Measurement of BSFC at different engine speeds and loads before and after the installation of an air fuel ratio controller represents a high level of diligence. The fractional change in fuel consumption is then corrected based on monthly monitored loads and RPM values to correct for actual site conditions.
	Total Quantity of Fuel Displaced Through Use of Vent Gases as Supplemental Fuel in Project / Fuel Displaced	m^3 natural gas equivalent	N/A	Calculated based on the energy content, composition and mass flow rate of vent gas input into the engine to determine the equivalent quantity of fuel displaced.	N/A	Quantity being Calculated. This quantity represents the incremental fuel savings from the use of a waste vent gas stream as a supplemental fuel (these fuel savings would be in addition to the fuel savings from the implementation of an air-fuel ratio controller).
	Mass of Fuel Gas Fed into the Engine from the Main Fuel Supply/ Mass $_{FUEL\ GAS}$	kg per month	Measured	Continuous measurement of the fuel flow rate on a mass basis for the primary fuel meter. Note that the primary fuel meter will be the only fuel meter for project configurations that do not capture vent gas.	Continuous metering and monthly aggregation of values.	Frequency of metering is highest level possible. For the purposes of this protocol, continuous monitoring means collecting one data point at least every fifteen minutes.
	Density of Fuel Gas/ Density $_{FUEL\ GAS}$	kg/ m^3	Measured	Calculated based on the molar composition of the fuel gas at 15°C and 101.3kPa, the standard reference conditions used by the natural gas	Annual fuel gas sampling	Frequency of metering provides for reasonable diligence as gas composition is likely to remain fairly consistent in the majority of projects.

				industry. Gas analyses are typically completed by a third party laboratory. See Appendix C-3 for further detail.		
	Mass of Vent Gas Consumed in the Engine as a Supplemental Fuel Source / Mass $_{VENT\ GAS}$	kg per Month	Measured	Continuous measurement of the vent gas flow rate on a mass basis for the secondary fuel source meter in the project condition. Note that this value will be zero for projects that do not involve the capture of vent gases.	Continuous metering and monthly aggregation of values.	Frequency of metering is highest level possible. For the purposes of this protocol, continuous monitoring means collecting one data point at least every fifteen minutes.
	Density of Vent Gas / Density $_{VENT\ GAS}$	kg/ m^3	Measured	Calculated based on molar composition of vent gas components at 15°C and 101.3kPa, the standard reference conditions used by the natural gas industry. See Appendix C-3 for further detail.	Annual or semi-annual vent gas sampling	Frequency of metering provides for reasonable diligence. The majority of vent gas streams will be consistent in composition based on their origin (e.g. natural gas transmission systems) and their compositions can therefore be derived from natural gas analyses completed at the facility. For other vent gas streams with more variable compositions (e.g. storage tank tops and dehydrator reboiler vents) a gas analysis should be completed semi-annually.
	Lower Heating Value of Vent Gas/ LHV $_{VENT\ GAS}$	GJ/m^3	Measured	Measured by a third party gas analysis or calculated based on gas composition. See Appendix C-3 for further detail.	Annual or semi-annual vent gas sampling	Frequency of metering provides for reasonable diligence.
	Lower Heating Value of Fuel Gas/ LHV $_{FUEL\ GAS}$	GJ/m^3	Measured	Measured by a third party gas analysis or calculated based on gas composition. See Appendix C-3 for further detail.	Annual fuel gas sampling	Frequency of metering provides for reasonable diligence.

	CO_2 Emissions Factor for Combustion of Fuel Gas/ EF Fuel $_{i\ CO2}$	kg CO_2 per m^3	Estimated	Calculated based on the molecular composition of each carbon-containing compound measured from the fuel gas analysis. Refer to Appendix D for the method to calculate the emission factor and Appendix C-3 for a sample fuel gas analysis.	Annual	The use of site specific fuel gas analyses to determine the carbon content of the fuel gas represents best practice. This approach accounts for variability in natural gas composition from site to site.
	CH_4 Emissions Factor for Combustion of Fuel Gas / EF Fuel $_{i\ CH4}$	kg CH_4 per m^3	Estimated	From Environment Canada reference documents. The project proponent may choose to use the emission factor for producer consumption of natural gas in place of the default for industrial consumption of natural gas if applicable.	Annual	Reference values adjusted annually as part of Environment Canada reporting on Canada's emissions inventory. If equipment specific CH_4 emission factors are available from US EPA AP-42 or the equipment manufacturer, then the default EC values may be substituted.
	N_20 Emissions Factor for Combustion of Fuel Gas / EF Fuel $_{i\ N2O}$	kg N_2O per m^3	Estimated	From Environment Canada reference documents. The project proponent may choose to use the emission factor for producer consumption of natural gas in place of the default for industrial consumption of natural gas if applicable.	Annual	Reference values adjusted annually as part of Environment Canada reporting on Canada's emissions inventory. If equipment specific N_2O emission factors are available from US EPA AP-42 or the equipment manufacturer, then the default EC values may be substituted.
B5b Venting of Emissions Captured in Project	$Emissions_{Vent\ Gases} = [(Mass_{VENT\ GAS} / Density_{VENT\ GAS}) * \%\ CH_4 * \rho\ CH_4 * GWP_{CH4}] - \sum (Mass_{VENT\ GAS} / Density_{VENT\ GAS}) * \%\ C_nH_m * \rho\ C_nH_m * [12\ n/(m+12n)] * 44/12$					
	Emissions $_{Vent\ Gases}$	kg of CO_2e	N/A	N/A	N/A	Quantity being calculated.
	Mass of Vent Gas Consumed in the Engine as a Supplemental Fuel Source in the Project Condition/ Mass $_{VENT\ GAS}$	kg per Month	Measured	Continuous measurement of the vent gas flow rate into the unit on a mass basis in the project condition.	Continuous metering and monthly aggregation of values.	Frequency of metering is highest level possible. For the purposes of this protocol, continuous monitoring means collecting one data point at least every fifteen minutes.

	Density of Vent Gas / Density $_{VENT\ GAS}$	kg/ m^3	Measured	Calculated based on molar composition of vent gas components measured in the project condition at 15°C and 101.3kPa, the standard reference conditions used by the natural gas industry. See Appendix C for further detail.	Annual vent gas sampling	Frequency of metering provides for reasonable diligence. The majority of vent gas streams will be consistent in composition based on their origin (e.g. natural gas transmission systems) and their composition can therefore be derived from natural gas analyses completed at the facility.
	Percentage Methane Contained in Captured Vent Gas / % CH_4	% Volume	Measured	Direct measurement of composition of captured gases in the project condition on an annual basis if vent gases are similar in composition to natural gas. For other vent gas streams with more variable compositions (e.g. storage tank tops and dehydrator reboiler vents) a gas analysis should be completed semi-annually.	Annual or semi-annual vent gas sampling	Direct measurement provides high level of diligence. Frequency of metering provides for reasonable diligence.
	Density of Methane / ρ CH_4	kg / m^3	Constant	0.678 kg/m^3 at 15°C and 101.3kPa, the standard reference conditions used by the natural gas industry.	Reference Value	N/A
	Global Warming Potential of Methane / GWP $_{CH4}$	kg CO_2e/ kg CH_4	Constant	Value set to 21 consistent with the Environment Canada National GHG Inventory	Reference Value	N/A
	% Volume of Each Hydrocarbon Contained in the Captured Vent Gas Stream/ %C_nH_m	% Volume	Measured	Direct measurement of composition of captured gases in the project condition on an annual basis if vent gases are similar in composition to natural gas. For other vent gas streams with more variable compositions (e.g. storage tank tops and dehydrator reboiler vents) a gas analysis should be completed semi-	Annual or semi-annual vent gas sampling	Represents an appropriate level of detail for captured gas streams with different compositions. Only those hydrocarbon components that make up more than 3% of the total gas stream need to be included. 'n' represents the number of carbon atoms and 'm' represents the number of hydrogen atoms in the compound.

				annually.		
	Density of Each Hydrocarbon Compound / ρ C_nH_m	kg/m^3	Estimated	Densities from reference documents at 15°C and 101.3kPa. Only the hydrocarbons that make up 3% or more of the total volume need to be quantified.	N/A	Standard values available for most chemical species at these reference conditions.
	Fraction of Carbon in Compound / $12n/(m+12n)$	kg Carbon/ kg C_nH_m	N/A	Based on the mass of carbon contained in each compound, where ‘n’ represents the number of carbon atoms and ‘m’ represents the number of hydrogen atoms. Obtained from chemical formula for each hydrocarbon (e.g. For CH_4 n=1 and m=4, for C_2H_6 n=2 and m=6 etc.)	N/A	Standard values for each chemical species based on chemical formula and molecular weight.

2.5.2. Contingent Data Approaches

Contingent means for calculating or estimating the required data for the equations outlined in section 2.5.1 are summarized in **TABLE 2.6**, below.

2.6 Management of Data Quality

In general, data quality management must include sufficient data capture such that the mass and energy balances may be easily performed with the need for minimal assumptions and use of contingency procedures. The data should be of sufficient quality to fulfill the quantification requirements and be substantiated by company records for the purpose of verification.

The project proponent shall establish and apply quality management procedures to manage data and information. Written procedures should be established for each measurement task outlining responsibility, timing and record location requirements. The greater the rigour of the management system for the data, the more easily an audit will be to conduct for the project.

2.6.1 Record Keeping

Record keeping practises should include:

a. Electronic recording of values of logged primary parameters for each measurement interval;
b. Printing of monthly back-up hard copies of all logged data;
c. Written logs of operations and maintenance of the project system including notation of all shut-downs, start-ups and process adjustments;
d. Retention of copies of logs and all logged data for a period of 7 years; and
e. Keeping all records available for review by a verification body.

2.6.1 Quality Assurance/Quality Control (QA/QC)

QA/QC can also be applied to add confidence that all measurements and calculations have been made correctly. These include, but are not limited to:

a. Protecting monitoring equipment (sealed meters and data loggers);
b. Protecting records of monitored data (hard copy and electronic storage);
c. Checking data integrity on a regular and periodic basis (manual assessment, comparing redundant metered data, and detection of outstanding data/records);
d. Comparing current estimates with previous estimates as a ‘reality check’;
e. Provide sufficient training to operators to perform maintenance and calibration of monitoring devices;
f. Establish minimum experience and requirements for operators in charge of project and monitoring; and
g. Performing recalculations to make sure no mathematical errors have been made.

TABLE 2.6: Contingent Data Collection Procedures

1. Project / Baseline SS	2. Parameter / Variable	3. Unit	4. Measured / Estimated	5. Contingency Method	6. Frequency	7. Justify measurement or estimation and frequency
Project SS's						
P1 Fuel Extraction and Processing	None					
P4 Unit Operation	None					
P5b Capture of Vent Gases	None					
Baseline SS's						
B1 Fuel Extraction and Processing	Volume of Each Type of Fuel / Vol Fuel $_i$	m^3	Estimated	Interpolation of previous and following months fuel consumption, provided that facility records demonstrate similar hours of operation for the specific engine.	Monthly	Provides reasonable estimate of the parameter, when the more accurate and precise method cannot be used.
B4 Unit Operation	Fractional Change in Fuel Consumption from Baseline to Project/ Fractional Change $_{B\text{-}P}$	-	Estimated	Interpolation of previous and following months fractional change in fuel consumption, provided that facility records demonstrate similar hours of engine operation, engine loading and RPMs.	Monthly	Provides reasonable estimate of the parameter, when the more accurate and precise method cannot be used.
	Mass of Fuel Gas Fed into the Engine from the Main Fuel Supply/ Mass $_{FUEL\ GAS}$	kg per month	Estimated	Calculation of average fuel consumption per hour of operation over previous and following months where fuel consumption measurements are available. Total fuel consumption is calculated based on reconciliation of unit operating hours from facility records multiplied by the average hourly fuel consumption.	Monthly	Provides reasonable estimate of the parameter, when the more accurate and precise method cannot be used.
	Density of Fuel Gas/ Density $_{FUEL\ GAS}$	kg/m^3	Measured	Estimated from reference value for natural gas.	Annual	Provides reasonable estimate of the parameter where the more accurate method cannot be used.

	Mass of Vent Gas Consumed in the Engine as a Supplemental Fuel Source / Mass $_{VENT\ GAS}$	kg per Month	Estimated	Calculation of average vent gas consumption per hour of operation over previous and following months where vent gas flow measurements are available. Total vent gas consumption is calculated based on reconciliation of unit operating hours from facility records multiplied by the average hourly vent gas consumption.	Monthly	Provides reasonable estimate of the parameter as vent gas flow rates will likely be consistent for most projects.
	Density of Vent Gas / Density $_{VENT\ GAS}$	kg/ m^3	Estimated	Estimated from reference value for natural gas for sources of vent gas that can reliably be shown to originate from vents on natural gas transmission equipment (e.g. instrument gas and compressor rod packing gas). For other sources of vent gases with more variable compositions, density may be estimated from engineering calculations, simulator output or other published industry data (e.g. CAPP).	Annual	Provides reasonable estimate of the parameter as vent gas flow rates will likely be consistent for most projects or can be reasonably estimated using standard industry methods.
	Lower Heating Value of Vent Gas/ LHV $_{VENT\ GAS}$	GJ/m^3	Measured	Calculated based on % composition of major components in vent gas from most recent gas analysis and comparison to a reference LHV for natural gas.	Annual	Represents a reasonable approximation when the more accurate method cannot be used.
	Lower Heating Value of Fuel Gas/ LHV $_{FUEL\ GAS}$	GJ/m^3	Measured	Estimated from reference values or previous gas analyses completed at the facility within the past three years.	Annual	Represents a reasonable approximation based on typical natural gas lower heating values.
B5b Venting of Emissions Captured in Project	Mass of Vent Gas Consumed in the Engine as a	kg/ month	Measured	Reconciliation of vent gas consumption on an hourly basis where consistent flow	Monthly	Provides reasonable estimate of the parameter for vent gas flow rates that maintain consistent flow rates.

	Supplemental Fuel Source in the Project Condition/ Mass $_{VENT\ GAS}$			rates can be demonstrated. Total vent gas consumption can also be calculated based on reconciliation of unit operating hours from facility records multiplied by the average hourly vent gas consumption, for vent gas streams with consistent flow rates. Project proponents may need to demonstrate that vent gas sources are consistent in flow rate as intermittent vent sources may not be fully measurable at this frequency.		
	Density of Vent Gas / Density $_{VENT\ GAS}$	kg/m^3	Estimated	Estimated from reference value for natural gas for sources of vent gas that can reliably be shown to originate from vents on natural gas transmission equipment (e.g. instrument gas and compressor rod packing gas). For other sources of vent gases with more variable compositions (e.g. dehydrator re-boiler vents and tank vents), density may be estimated from engineering calculations, simulator output or other published industry data (e.g. CAPP).	Monthly	Provides reasonable estimate of the parameter, when the more accurate and precise method cannot be used.
	Percentage Methane Contained in Captured Vent Gas / % CH_4	% Volume	Estimated	Interpolation of previous and following measurements taken.	Annual	Provides reasonable estimate of the parameter, when the more accurate and precise method cannot be used.
	% Volume of Each Hydrocarbon Contained in the Captured Vent Gas	% Volume	Estimated	Estimated from reference value for natural gas for sources of vent gas that can reliably be shown to originate	Annual	Represents an appropriate level of detail for captured gas streams with different compositions.

	Stream/ $\%C_nH_m$			from vents on natural gas transmission equipment (e.g. instrument gas and compressor rod packing gas). For other sources of vent gases with more variable compositions, compositions may be estimated from engineering calculations, process simulator output or other published industry data (e.g. CAPP).		

APPENDIX A

Quantification Procedures for Flexibility Mechanisms

Flexibility Mechanisms: Note to Project Developers

Two flexibility mechanisms are quantified in the following table in order to accommodate project configurations that do not fit the above quantification approaches due to data limitations or other site specific factors.

The first flexibility mechanism was developed for sites that are or were not able to measure the brake specific fuel consumption before the installation of an engine management system and are or were not able to determine the fractional change in fuel consumption at engine speeds and loads currently operated at in the project condition. The main situations where this might occur would be for projects installed before the publication of this protocol, sites that were not able to complete full Pre and Post-Audits due to operating restrictions or sites that experienced significant changes in engine loading over time (e.g. declining reserves or the addition of new loads) resulting in a higher or lower fuel savings than the original conditions of the Pre and Post-Audits. It may also be possible that an engine management system could be installed directly onto a brand new engine as a cost effective way to set up the equipment rather than to install the Original Equipment Manufacturer (OEM) engine management system, run the unit to obtain the BSFC at 1-3 different loads and 3 RPMs, then remove the OEM engine management system and install the new engine management system to obtain post-installation BSFC data to calculate the fractional change in fuel consumption at different RPMs.

This protocol relies on direct measurement of the fuel consumption of the engine before the equipment modification and after, which provides a high level of accuracy for the fuel savings at the time of installation. However, once the equipment modification has been made it is <u>irreversible</u> and the original conditions cannot be re-created again. Therefore, if the operating conditions (e.g. loads) change significantly over time and if the original measurements were only conducted within a limited window of operating loads and RPMs, then the potential for inaccuracy in the fuel savings estimate increases. The simple quantification approach used in this protocol attempts to minimize inaccuracies by providing a method to normalize engine efficiency improvements if a significant load change occurs (see Appendix C-1). The flexibility mechanism included below is intended to provide an alternate method to estimate fuel savings across a range of engine loads for specific classes of engines and types of engine management systems once sufficient data is available to characterize the performance of these systems in a generic way.

Additionally, it is important to note that the relative magnitude of GHG emission reductions (offsets) that could be obtained from the fuel efficiency improvement gained from the implementation of a new engine management system is relatively small and is likely to be between 200 to 800 tCO2e / year. On an individual project basis, the incremental value of these offsets is relatively small compared to the upfront costs of the engine management system and the costs to bring the offsets to market, which could include costs related to data collection/management, project documentation, third party verification, registration and marketing. Therefore to encourage maximum uptake of engine management systems and related technologies across the upstream oil and gas industry, it is necessary to develop an approach that reduces the administrative burdens of offset project development <u>at such a time</u>

as sufficient data exists within the industry to conservatively estimate the offsets on average for a typical installation. It is reasonable to assume that this level of conservativeness can be achieved after 5 installations of the same engine management system on the same make and classification of the engine (e.g. Large turbo-charged stoichiometric engines such as the Waukesha VHP Series, refer to Appendix C-1 for typical engine classifications), provided that the results are documented following the approach used in this protocol.

The second flexibility mechanism was developed for sites where there is a requirement to flare waste gas streams and/or where the baseline practice was flaring of waste gases that have now been re-directed to an engine for use as supplemental engine fuel in the project. In these situations the GHG reductions from avoiding the venting of gases containing methane in the baseline do not apply and a separate quantification approach is required. The GHG reductions from avoiding the flaring of waste gases could include the displacement of a conventional fuel source with the waste gas stream, the reduction in the use of fuel to supplement the flare (makeup fuel gas, purge gas and pilot gas) and a small reduction in methane emissions due to the improved methane destruction efficiency of a controlled combustion device (e.g. an engine) as compared to a flare. The goal of this flexibility mechanism is to provide an additional incentive for upstream oil and gas facility operators to develop projects that make productive use of waste gas streams normally flared as standard industry practice or required by a regulatory agency.

In order to establish the baseline flare efficiency for use in this protocol a literature study was done to assess the best available information on the subject in Canada and in North America. In most cases, it is expected that the project proponent will not have access to flare combustion efficiency tests and that the most reasonable approach would be to assume a conservative value for the flare destruction efficiency in the baseline. The destruction efficiency of a flare depends on a number of factors including the heating value or energy density of the flare stream, the wind speed, gas exit velocity, flare stack diameter and the presence of liquids in the gas stream[9].

The 8 year University of Alberta (U of A) Flare Research Project led by Kostiuk, Johnson, and Thomas et al. has been the most comprehensive study completed to date in Alberta on the parameters that impact flare efficiency. Among the highlights of the program, the UofA team concluded that wind speeds had a strong impact on combustion efficiency. At low crosswinds, the efficiencies were very high (> 99 %), but as cross wind was increased the efficiency fell dramatically. Further, The U of A team established that the effects of liquid droplets entrained in the flare stream were significant as the combustion efficiency at low wind speeds dropped from ~99% to ~93%[10]. The effects of changing energy density were examined in detail and it was found that lowering the energy density of the fuel had a profound impact on the flare efficiency. The U of A work predicted that a standard 114 mm diameter flare burning a non-sooting, gaseous fuel of 20 MJ/m^3 would have a yearly averaged efficiency of greater than 98%[11]. Based on this model and field data, the

[9] Kostiuk, Larry. Johnson, Matthew, and Thomas, Glen. University of Alberta Flare Research Project. Final Report September 2004. University of Alberta.
[10] ibid
[11] ibid

recommendation was made to the ERCB to raise the lowest permissible energy density to be flared from 9 MJ/m^3 to 20 MJ/m^3,[12] which the ERCB implemented in 2005[13].

The U of A work agreed well with work done earlier by Pohl et al. for the US EPA in 1986 that demonstrated that destruction efficiencies were typically in the 95-99% range and would exceed 98% provided that the flare was operated within its envelope of stable operating conditions[14]. More recently the US EPA published CFR 40 60.18 as part of the New Source Performance Standards, which assumes greater than 98% destruction efficiency if the energy content of the gas is greater than 7.45 MJ/m^3 and the maximum exit velocity is less than 18.3 m/s for non-assisted flares and greater than 11.2 MJ/m^3 and less than 18.3 m/s for steam or air-assisted flares[15].

1. Based on a review of the sources mentioned above and the Alberta ERCB Directive 60 requirements for flare gas streams to maintain a net heating value of 20 MJ/m^3 and to operate liquid separation equipment to prevent liquid carry-over, it was concluded that a 98.5% baseline methane destruction efficiency would be representative of the majority of flares operating in Alberta. The destruction efficiencies for incinerators, as they are defined in Section 7.1 in Directive 60 based on residence time and exit temperature, are assumed to exceed 99% and therefore for conservativeness in this protocol the baseline methane destruction efficiency for incinerators is assumed to be 99.5%.

[12] ibid

[13] Alberta Energy Resources Conservation Board (ERCB) Directive 60 Upstream Petroleum Industry Flaring, Incinerating, and Venting. November 16, 2006.

[14] Pohl, J.H. Lee, J. Payne R. and Tichenor B.A. Energy and Environmental Research Corp. Combustion Efficiency of Flares. Combustion Science and Technology. Volume 50, No 4-6. 1986.

[15] US EPA New Source Performance Standards CFR 40 Part 60.18. July 1, 2006.

1. Project/ Baseline SS	2. Parameter / Variable	3. Unit	4. Measured / Estimated	5. Contingency Method	6. Frequency	7. Justify measurement or estimation and frequency
Flexibility Mechanisms						
B4 Unit Operation	Emissions $_{Unit\ Operation}$ = ∑ (Fuel Consumption $_i$ * Fractional Change $_{B\text{-}P}$ * (1-AF) * EF Fuel $_{CO2}$); ∑ (Fuel Consumption $_i$ * Fractional Change $_{B\text{-}P}$ *(1-AF) * EF Fuel $_{CH4}$) ; ∑ (Fuel Consumption $_i$ * Fractional Change $_{B\text{-}P}$ * (1-AF)* EF Fuel $_{N20}$)					
	Emissions $_{Unit\ Operation}$	kg of CO_2 ; CH_4 ; N_2O	N/A	N/A	N/A	Quantity being calculated.
	Total Fuel Consumption in Project Condition/ Fuel Consumption $_i$	m3	Measured	Continuous measurement of fuel consumption in project condition.	Continuous metering and monthly averaging of values.	Frequency of metering is highest level possible. For the purposes of this protocol, continuous monitoring means collecting one data point at least every fifteen minutes.
	Fractional Change in Fuel Consumption from Baseline to Project Due to Implementation of an Engine Management System / Fractional Change $_{B\text{-}P}$	-	Estimated	The Fractional Change in fuel consumption from the baseline to the project condition is estimated based on measured industry Break Specific Fuel Consumption (BSFC) data from at least 5 engines of the same make and classification (e.g. Large turbo-charged stoichiometric engines such as the Waukesha VHP Series, see Appendix C-1) all retrofitted with the same type of engine management system. The average fractional change in fuel consumption for the set of engines can be used in project	Determined from representative industry BSFC measurements made pre and post installation and monthly average engine speeds and loads in the project condition	The use of industry data from at least 5 of the same type of engines retrofitted with the same engine management system provides reasonable assurance that site to site and engine to engine variations are minimized. The use of the average fractional change in fuel consumption from these 5 field installations is reasonable when combined with an adjustment factor.

				configurations where metered data is unavailable provided that the industry data has been collected in accordance with the methods outlined in Appendix C of this protocol or at an equivalent standard.		
	Adjustment Factor / AF	%	N/A	Adjustment Factor used to account for variability between fuel consumption for engines of the same make and classification due to different site operating conditions and maintenance practices. Adjustment Factor calculated from 5 measured field data sets for a given engine make and classification (see Appendix C-1 for typical engine classifications), with the AF equal to the standard deviation as a percent of the Fractional Change in Fuel Consumption at the rated load and RPM to ensure the conservativeness of the emission reduction calculation.	N/A	Represents a reasonable approach to conservatively estimating the baseline fuel consumption when using a reference brake specific fuel consumption curve rather than one developed for the project unit.
	CO_2 Emissions Factor for Natural Gas / EF Fuel $_{i\ CO2}$	kg CO_2 per m^3	Calculated	Calculated based on the molecular composition of each carbon-containing compound measured from the fuel gas analysis. Refer to Appendix D for the method to calculate the emission factor and Appendix C-3 for a sample fuel gas analysis.	Annual	The use of site specific fuel gas analyses to determine the carbon content of the fuel gas represents best practice. This approach accounts for variability in natural gas composition from site to site.

	CH_4 Emissions Factor for Natural Gas / EF Fuel $_{i\ CH4}$	kg CH_4 per m^3	Estimated	From Environment Canada reference documents. The project proponent may choose to use the emission factor for producer consumption of natural gas in place of the default for industrial consumption of natural gas if applicable.	Annual	Reference values adjusted annually as part of Environment Canada reporting on Canada's emissions inventory. If equipment specific CH_4 emission factors are available from US EPA AP-42 or the equipment manufacturer, then the default EC values may be substituted.
	N_20 Emissions Factor for Natural Gas / EF Fuel $_{i\ N2O}$	kg N_2O per m^3	Estimated	From Environment Canada reference documents. The project proponent may choose to use the emission factor for producer consumption of natural gas in place of the default for industrial consumption of natural gas if applicable.	Annual	Reference values adjusted annually as part of Environment Canada reporting on Canada's emissions inventory. If equipment specific N_2O emission factors are available from US EPA AP-42 or the equipment manufacturer, then the default EC values may be substituted.

1. Project/ Baseline SS	**2. Parameter / Variable**	**3. Unit**	**4. Measured / Estimated**	**5. Contingency Method**	**6. Frequency**	**7. Justify measurement or estimation and frequency**
Flexibility Mechanisms						
P6 Flaring of Process Emissions	Emissions $_{Flaring} = \sum$ (Vol. Flare Fuel * EF $_{CO2}$); $\sum$ (Vol. Flare Fuel * % CH_4 * ρ CH_4 * (1 - DE)) ; $\sum$ (Vol. Flare Fuel * EF $_{N2O}$) ; $\sum$ (Volume $_{Flared\ Gases}$ * % C_nH_m * ρ C_nH_m * [12n/(m+12n)] * 44/12) ; (Volume $_{Flared\ Gases}$ * % CH_4 * ρ CH_4 * (1 - DE) ; (Volume $_{Flared\ Gases}$ * EF $_{Flared\ Gases\ N2O}$)					
	Emissions $_{flaring}$	kg of CO_2 ; CH_4 ; N_2O	N/A	N/A	N/A	Quantity being calculated.

	Volume of Fuel Used to Supplement Flaring of Process Emissions / Vol. Flare Fuel	m^3	Measured or Estimated	Direct measurement of volume of fuel used to supplement flaring or reconciliation of monthly totals.	Continuous Monitoring or Reconciliation of Monthly Totals.	Frequency of metering is highest level possible. Reconciliation is reasonable as many flaring operations are intermittent in nature.
	Volume of Process Emissions Flared in Project / Volume Flared Gases	m^3	Measured or Estimated	Direct measurement of volume of process emissions sent to flare or reconciliation from operating records of flaring instances (e.g. due to equipment downtime).	Continuous Monitoring or Reconciliation of Monthly Totals.	Frequency of metering is highest level possible. Reconciliation is reasonable as many flaring operations are intermittent in nature.
	% Volume of Each Hydrocarbon Contained in the Process Emissions Stream/ $\%C_nH_m$	% Volume	Measured	Direct measurement of the composition of the gas stream re-directed to the unit in the project condition. Only those hydrocarbon components that make up more than 3% of the total gas stream need to be included.	Annual Gas Analysis	Represents an appropriate level of detail for gas streams with different compositions.
	Density of Each Hydrocarbon Compound / $\rho\ C_nH_m$	kg/m^3	Estimated	From reference documents (e.g. $\rho\ CH_4 = 0.7157\ kg/m^3$ at STP). Only the hydrocarbon components that make up greater than 3% of the total gas stream need to be quantified.	Annual Gas Analysis	Standard values for most chemical species at standard temperature and pressure.
	Fraction of Carbon in Compound / $12n/(m+12n)$	kg Carbon/ kg C_nH_m	N/A	Based on the mass of carbon contained in the compound, where 'n' represents the number of carbon atoms and 'm' represents the number of hydrogen atoms. Obtained from chemical formula for each hydrocarbon (e.g. For CH_4 n=1, for C_2H_6 n=2 etc.)	Annual Gas Analysis	Standard values for each chemical species based on chemical formula and molecular weight.

	Percentage Methane Contained in Process Emissions / % CH_4	% Volume	Measured	Direct measurement of composition of process emissions sent to flare in the project condition.	Annual Gas Analysis	Direct measurement provides high level of diligence. Frequency of metering provides for reasonable diligence.
	Density of Methane / ρ CH_4	kg / m^3	Constant	0.678 kg/m^3 at 15°C and 101.3kPa, the standard reference conditions used by the natural gas industry.	Reference Value	Density should be corrected if actual temperatures and pressures of the gas stream are not consistent with reference values.
	CO_2 Emissions Factor for Combustion of Supplemental Flare Fuel / EF_{CO2}	kg CO_2 per L, m^3 or other	Estimated	Calculated based on the molecular composition of each carbon-containing compound measured from the fuel gas analysis. Refer to Appendix D for the method to calculate the emission factor and Appendix C-3 for a sample fuel gas analysis. Alternatively, the CO_2 Emission factor for sales/pipeline quality natural gas or propane from Environment Canada can be obtained from reference documents.	Annual	The use of site specific fuel gas analyses to determine the carbon content of the fuel gas represents best practice. This approach accounts for variability in natural gas composition from site to site. Reference values adjusted annually as part of Environment Canada reporting on Canada's emissions inventory.
	Destruction Efficiency of Flare / DE	-	98.5% for flares and 99.5% for incinerators	The methane emission factor was calculated based on the assumed destruction efficiency of the flare. The destruction efficiency was assumed to be 98.5% for flares and 99.5% for incinerators based on studies conducted by the University of Alberta, US EPA and the ERCB Directive 60 flare operating requirements. Specifically ERCB D60	N/A	Represents the most comprehensive research on flare destruction efficiency in Canada based on over 8 years of research, modelling and field testing.

				requires flares to have liquid separators and ensure that the flare gas net heating value be at least 20 MJ/m^3. Further details are provided at the beginning of Appendix A on the parameters that impact flare destruction efficiency.		
	N_20 Emissions Factor for Combustion of Supplemental Flare Fuel / EF_{N2O}	kg N_2O per L, m^3 or other	Estimated	N_2O Emission factor for combustion of sales/pipeline quality natural gas or propane from Environment Canada reference documents.	Annual	Reference values adjusted annually as part of Environment Canada reporting on Canada's emissions inventory.
	N_20 Emissions Factor for Flaring of Process Emissions / $EF_{Flared\ Gases\ N2O}$	kg N_2O per m^3	Estimated	Emission factor for natural gas used to represent N_2O emissions from flaring of process emissions. From Environment Canada reference documents. Reference value for producer consumption of natural gas to be used if flared gas stream source is not pipeline grade (sales) natural gas.	Annual	Reference values adjusted annually as part of Environment Canada reporting on Canada's emissions inventory.
B6 Flaring of Process Emissions	$Emissions_{Flaring} = \sum (Vol.\ Flare\ Fuel * EF_{CO2}); \sum (Vol.\ Flare\ Fuel * \%\ CH_4 * \rho\ CH_4 * (1 - DE)) ; \sum (Vol.\ Flare\ Fuel * EF_{N2O}) ; \sum ((Mass_{Captured\ Gases} / Density_{Captured\ Gases}) * \%\ C_nH_m * \rho\ C_nH_m * [12n/(m+12n)] * 44/12) ; (Mass_{Captured\ Gases} / Density_{Captured\ Gases}) * \%\ CH_4 * \rho\ CH_4 * (1 - DE)) ; (Mass_{Captured\ Gases} / Density_{Captured\ Gases}) * EF_{Captured\ Gases\ N2O})$ **Note:** When applying this flexibility mechanism and quantifying GHG emissions from Unit Operation under SS B4 in TABLE 2.5. Project Proponents should follow the same approach in B4 as for vent gas capture projects and replace the relevant "vent gas" parameters with relevant data for the gas stream sent to flare in order to determine the fuel displaced through the use of waste gases as supplemental fuel.					
	$Emissions_{flaring}$	kg of CO_2 ; CH_4 ; N_2O	N/A	N/A	N/A	Quantity being calculated.

	Volume of Fuel Used to Supplement Flaring of Process Emissions / Vol. Flare Fuel	m3	Calculated	Calculated based on flare design specifications (flare tip diameter and flare stack diameter), flow rate of gases flared, typical heat value of gas stream sent to flare and heat value of fuel used to supplement flaring. Fuel Gas usage is the sum of pilot gas, purge gas and makeup gas.	Monthly	Method represents reasonable diligence since metered data is not likely to be available. Project proponents should refer to the *Fuel Gas Best Management Practices series of documents Module 4 Efficient Use of Fuel Gas for Flaring Operations* for reference tables and formulas to estimate typical purge gas, pilot gas and makeup gas usage for flares.
	Mass of Process Emissions Combusted in Unit in Project / Mass Captured Gases	kg	Measured	Direct measurement of mass of captured gases fed into the engine in the project condition (that would have normally been flared in the baseline).	Continuous Metering or Reconciliation of Monthly Totals.	Frequency of metering is highest level possible. Frequency of reconciliation represents reasonable diligence.
	Density of Process Emissions in Project Condition / Density Captured Gases	kg/ m^3	Measured	Calculated based on molar composition of process emission components measured in the project condition at 15°C and 101.3kPa, the standard reference conditions used by the natural gas industry. See Appendix C-3 for further detail.	Annual Gas Analysis	Represents an appropriate level of detail for captured gas streams with different compositions.
	% Volume of Each Hydrocarbon Contained in the Process Emissions Stream/ $\%C_nH_m$	% Volume	Measured	Direct measurement of the composition of the gas stream re-directed to the unit in the project condition. Only those hydrocarbon components that make up more than 3% of the total gas stream need to be included.	Annual Gas Analysis	Represents an appropriate level of detail for captured gas streams with different compositions.

	Density of Each Hydrocarbon Compound / $\rho\ C_nH_m$	kg/m^3	Estimated	From reference documents (e.g. $\rho\ CH_4 = 0.7157\ kg/m^3$ at STP). Only the hydrocarbon components that make up greater than 3% of the total gas stream need to be quantified.	N/A	Standard values for most chemical species at standard temperature and pressure.
	Fraction of Carbon in Compound / 12n/(m+12n)	kg Carbon/ kg C_nH_m	N/A	Based on the mass of carbon contained in the compound, where 'n' represents the number of carbon atoms and 'm' represents the number of hydrogen atoms. Obtained from chemical formula for each hydrocarbon (e.g. For CH_4 n=1, for C_2H_6 n=2 etc.)	N/A	Standard values for each chemical species based on chemical formula and molecular weight.
	Percentage Methane Contained in Process Emissions / % CH_4	% Volume	Measured	Direct measurement of composition of process emissions sent to flare in the project condition.	Annual Gas Analysis	Direct measurement provides high level of diligence. Frequency of metering provides for reasonable diligence.
	Density of Methane / $\rho\ CH_4$	kg / m^3	Constant	$0.678\ kg/m^3$ at 15°C and 101.3kPa, the standard reference conditions used by the natural gas industry.	Reference Value	Density should be corrected if actual temperatures and pressures of the gas stream are not consistent with reference values.
	CO_2 Emissions Factor for Combustion of Supplemental Flare Fuel / EF_{CO2}	kg CO_2 per L, m^3 or other	Estimated	Calculated based on the molecular composition of each carbon-containing compound measured from the fuel gas analysis. Refer to Appendix D for the method to calculate the emission factor and Appendix C-3 for a sample fuel gas analysis. Alternatively, the CO_2 Emission factor for combustion of sales/pipeline	Annual	The use of site specific fuel gas analyses to determine the carbon content of the fuel gas represents best practice. This approach accounts for variability in natural gas composition from site to site. Reference values adjusted annually as part of Environment Canada reporting on Canada's emissions

				quality natural gas or propane from Environment Canada reference documents.		inventory.
	Destruction Efficiency of Flare / DE	-	98.5% for flares and 99.5% for incinerators	The methane emission factor was calculated based on the assumed destruction efficiency of the flare. The destruction efficiency was assumed to be 98.5% for flares and 99.5% for incinerators based on studies conducted by the University of Alberta, US EPA and the ERCB Directive 60 flare operating requirements. Specifically ERCB D60 requires flares to have liquid separators and ensure that the flare gas net heating value be at least 20 MJ/m^3. Further details are provided at the beginning of Appendix A on the parameters that impact flare destruction efficiency.	N/A	Represents the most comprehensive research on flare destruction efficiency in Canada based on over 8 years of research, modelling and field testing. The ERCB Directive requirements are intended to ensure destruction efficiencies of 98% or greater.
	N_20 Emissions Factor for Combustion of Supplemental Flare Fuel / EF_{N2O}	kg N_2O per L, m^3 or other	Estimated	N_2O Emission factor for combustion of sales/pipeline quality natural gas or propane from Environment Canada reference documents.	Annual	Reference values adjusted annually as part of Environment Canada reporting on Canada's emissions inventory.
	N_20 Emissions Factor for Flaring of Process Emissions / $EF_{\text{Captured Gases N2O}}$	kg N_2O per m^3	Estimated	Emission factor for natural gas used to represent N_2O emissions from flaring of process emissions. From Environment Canada reference documents. Reference value for	Annual	Reference values adjusted annually as part of Environment Canada reporting on Canada's emissions inventory.

				producer consumption of natural gas to be used if flared gas stream source is not pipeline grade (sales) natural gas.		

APPENDIX B

Contingent Data Collection Procedures for Flexibility Mechanisms

Contingent Data Collection Procedures for Flexibility Mechanisms

1. Project/ Baseline SS	2. Parameter / Variable	3. Unit	4. Measured / Estimated	5. Contingency Method	6. Frequency	7. Justify measurement or estimation and frequency
Flexibility Mechanisms						
B4 Unit Operation	Total Fuel Consumption in Project Condition/ Fuel Consumption $_i$	m3 of fuel	Measured	Interpolation of previous and following measurements.	Continuous metering and monthly averaging of values.	Frequency of metering is highest level possible.
P6 Flaring of Process Emissions	Volume of Fuel Used to Supplement Flaring of Process Emissions / Vol. Flare Fuel	m^3	Estimated	Calculated based on flare design specifications (flare tip diameter and flare stack diameter), flow rate of gases flared, typical heat value of gas stream sent to flare and heat value of fuel used to supplement flaring. Fuel Gas usage is the sum of pilot gas, purge gas and makeup gas.	Monthly	Method represents reasonable diligence when more accurate method is unachievable. If metered data is unavailable project proponents should refer to the *Fuel Gas Best Management Practices series of documents Module 4 Efficient Use of Fuel Gas for Flaring Operations* for reference tables and formulas to estimate typical purge gas, pilot gas and makeup gas usage for flares.
	Volume of Process Emissions Flared in Project / Volume $_{\text{Flared Gases}}$	m^3	Estimated	Estimated based on facility operating records (upsets) and historical monthly flared volumes. If metered data and facility records are unavailable project proponents should use the highest monthly volume of gas flared in the past year as a conservative value.	Monthly Reconciliation	Method represents reasonable diligence when more accurate method is unachievable.

	% Volume of Each Hydrocarbon Contained in the Process Emissions Stream/ $\%C_nH_m$	% Volume	Estimated	Estimation of gas stream composition based on typical industry compositions at relevant upstream oil and gas facilities.	Annual	Method represents reasonable diligence when more accurate method is unachievable.
B6 Flaring of Process Emissions	Volume of Fuel Used to Supplement Flaring of Process Emissions / Vol. Flare Fuel	m3	Estimated	For conservativeness, project proponents may assume that no fuel is required to supplement flaring.	Annual	Represents a conservative approach to quantification of baseline emissions.
	Mass of Process Emissions Combusted in Unit in Project / $Mass_{Captured\ Gases}$	kg	Estimated	Interpolation of previous and following measurements. Project proponents should provide records of unit operating hours to ensure that process emissions were being used as supplemental fuel.	Monthly Reconciliation	Method represents reasonable diligence when more accurate method is unachievable.
	Density of Process Emissions in Project Condition / $Density_{Captured\ Gases}$	kg/m^3	Estimated	Estimation of gas stream composition based on typical industry compositions at relevant upstream oil and gas facilities.	Annual	Method represents reasonable diligence when more accurate method is unachievable.
	% Volume of Each Hydrocarbon Contained in the Process Emissions Stream/ $\%C_nH_m$	% Volume	Estimated	Estimation of gas stream composition based on typical industry compositions at relevant upstream oil and gas facilities.	Annual	Method represents reasonable diligence when more accurate method is unachievable.

APPENDIX C

Procedural Determination of Brake Specific Fuel Consumption[16]

[16] Appendix C has been developed with significant input from Power Ignition and Controls and REM Technology Inc.

PROCEDURAL DETERMINATION OF BRAKE SPECIFIC FUEL CONSUMPTION

This appendix is intended to provide the project proponent with a step-by-step approach to conducting a Pre and Post-Audit for the installation of an engine management system to determine the BSFC and fractional fuel savings from the project activity versus the baseline. This procedure represents best practice guidance and should be followed wherever possible. It is anticipated that this step-by-step approach will be applicable to the bulk of projects applying this protocol, but is by no means all encompassing and project proponents are expected to use professional judgement where the scope of their project is not consistent with this methodology.

Definition: Brake Specific Fuel Consumption, BSFC, is defined as the Fuel Energy Flow Rate divided by the Brake Power Output of the prime mover.

This procedure specifies that the BSFC be expressed in units of BTU/BHP-hr. All loads are specified in units of brake horsepower, BHP.

The Fuel Energy Flow rate is the product of the fuel mass flow rate times the fuel heat content per unit mass.

Brake Power Output is the brake power output of the prime mover including any auxiliary loads due to cooling fans, pumps etc.

Note: Measurements and calculations are a snap shot of conditions at the time data is collected. Mechanical engine soundness and or deficiencies have a direct bearing on recorded data and BSFC calculations.

1. **Mass Fuel Flow Rate**
   - **1.1.** A mass flow meter should be used to measure the fuel gas flow rate into the engine (e.g. Coriolis based mass flow meters manufactured by Micro Motion or thermal mass flow meters manufactured by Fox Thermal Instruments are commonly used). Standard measurement units are in kilogram fuel gas/hour. Sample calibration frequency requirements and standards are found in Appendix C-4.

2. **Fuel Heat Content**
   - **2.1.** A current fuel gas analysis is required in order to accurately determine fuel energy flow rate (24 months maximum). If a current fuel gas analysis is not available, a fuel gas analysis should be conducted by an independent commercial laboratory.
   - **2.2.** The Lower Heating Value (LHV) of the fuel gas is used in the BSFC calculation. Some fuel gas analyses provide the Gross Heating Value (GHV) only and therefore it is necessary to calculate a LHV for the fuel gas. A detailed calculation approach is shown in Appendix C-3, but generally the LHV will be 0.91 * GHV.

2.3. The LHV must be expressed in units of BTU/kg. If the heating value is expressed as heating value per unit volume it must be converted to heating value per unit mass, and if the heating value units are in MJ they must be converted to BTU.

2.3.1. LHV (MJ/m^3) * 1000 (kJ/MJ)/ [1.054 (BTU/kJ) * Density (kg/m^3)] = LHV (BTU/kg)

2.3.2. Fuel Gas Density is calculated by multiplying the mole fraction of each fuel component by the density of the fuel component and summing the result. See Appendix C-3 for a sample.

3. Fuel Energy Flow Rate

The Fuel Energy Flow Rate is calculated as the product of the mass fuel flow rate to the engine and the fuel heat content per unit mass.

Fuel Energy Flow Rate =Mass Flow Rate * heat content per unit mass
= kg/hr * BTU/kg

4. Brake Power Output

Brake Power Output is the total brake power output of the prime mover. The prime mover may be a compressor, generator, pump or other load. The load measurement procedures are described below for compressors. It is expected that the procedures to determine the break power output from a generator or other load would be considerably more straightforward than for a compressor and thus a step-by-step measurement procedure would not be required. For pumps, each manufacturer normally has a proprietary load calculation method.

For compressors, the break power output is the sum of the compressor load and the load due to auxiliary devices such as engine cooling fans, auxiliary cooling pumps and oil pumps. Certain compressor manufacturers (most notably Ariel and Superior) provide compressor power calculations based on suction and discharge pressures and temperatures, and the compressor speed. These calculations are recognized as industry standard; however the absolute[1] accuracy is approximately 5%. Therefore, where possible measured data from the Recip Trap should be used as the preferred data source for the Compressor Load.

4.1. Measured Load;

For a compressor, perform the Recip Trap power measurements with a Dynalco Controls model RT9260 Recip Trap or other equivalent device. The Recip Trap power measurement will be accurate to within 3% assuming correct measurement techniques.

4.1.1. Record calibration date of Recip Trap and ensure calibration is current.

4.1.2. Data collection is critical to the measurement phasing. Ensure the Recip Trap measurements are phased to the compressor as per Chapter 2 of the Dynalco Recip Trap Manual.

4.1.3. Calibration frequency requirements and standards are found in Appendix C-4.

4.1.4. Suction Pressure, Discharge Pressure and Engine Speed must be recorded at start of Recip Trap data collection and recorded at the end of the Recip Trap data collection.

4.1.5. A valid data collection "run" requires the Load stability must be within 3% during data collection. Should the load change by more than 3%, data must be deleted and a new run completed.

4.1.6. Compressor Friction; Measurement of the compressor friction is not possible. The industry standard is to allow 5%.

4.2. Calculated Compressor Load;

4.2.1. Record the compressor specifications and process parameters necessary for a compressor load report.

4.2.2. Where possible, record the process parameters (pressure, temperature etc.) with calibrated sensors.

4.2.3. Record calibration information and ensure calibrations are within valid time frame.

4.2.4. Ensure the compressor load report includes an allowance of 5% for compressor friction. If not, calculate a total compressor load equal to the compressor power divided by (1-friction%/100%)

4.3. Auxiliary Engine Load; Measurement of the Auxiliary engine load is not practical. Industry standard is to rate the load from auxiliary devices as per Table C-1, below;

4.3.1. Determine the rated load for the observed RPM. If not available from manufacturer's data, calculate the rated load at observed RPM = Full RPM brake power * Observed RPM/ Full Rated RPM.

[1]If the same calculation is used before and after the installation of an engine management system, the relative error which is based on pressure sensor calibration changes will be much smaller than the absolute error.

The project proponent must ensure that the same auxiliary equipment is operating in the Pre and Post-Audits and that any added or removed auxiliary loads have` been properly accounted for. Additionally, any modifications made to the prime mover (e.g. compressor) following the Pre-Audit could impact the load on the engine (e.g. reduced friction). Project proponents should ensure that any changes made to the engine, the prime mover or associated auxiliary equipment following the Pre-Audit (i.e. these changes could occur before or after the Post-Audit) have been documented to ensure accurate representation of the change in fuel consumption.

Table C.1 provides typical auxiliary loads that can be used in the absence of site specific data.

Table C.1- Typical Auxiliary Loads

Load Type	Auxiliary % of rated Load
Generator	2%
Gas Compressor	3.5%

5. BSFC Calculation

5.1. Calculate the total engine load at the specified engine speed:

Total engine brake load = Compressor Load {calculated or measured} + Compressor Friction + Auxiliary Load

Note that the equation for total engine brake load would still be the sum of the load from the prime mover plus auxiliary loads and parasitic loads for other prime movers (e.g. generators). Project proponents should refer to manufacturer specifications for the parasitic or frictional loads for generators, pumps or other prime movers powered by engines in the project condition.

For generators the friction and heat losses would normally be expressed as a loss percentage such that the total generator load would equal the measured generator power divided by (1- loss% / 100%).

5.2. Calculate the engine BSFC

BSFC = Fuel energy flow rate (BTU/hr) / Total engine brake load (BHP)

5.3. Specify engine speed (RPM) for the BSFC calculation

6. Pre-Audit

6.1. A Pre-Audit of the engine and compressor must be conducted prior to the installation of the engine management system to collect data necessary to apply this protocol and to obtain fuel gas consumption at different loads and RPMs for the unmodified engine. A fuel gas meter should be located such that the engine is the only fuel consumer at the measurement point (e.g. a portable Micro Motion meter can be installed in the fuel line to measure fuel consumption of the engine). The fuel meter should have a Zero calibration performed (see recommended Calibration practices in Appendix C-4). The data will be collected at three different engine speeds.

6.2. A fuel gas analysis is necessary to determine the fuel energy input into the engine. If the fuel gas analysis is out of date or unavailable, one should be completed by an independent laboratory.

6.3. The air fuel ratio and ignition advance should be recorded during the Pre-Audit.

6.4. The Recip Trap should be utilized to measure compressor load as the preferred data source. If the compressor does not have pressure access ports, data should be collected to utilize an engineering calculation method to determine load. If the project configuration does not include a compressor, other industry standards may be used to determine loads. For each load measurement data should be collected at three different engine speeds (RPMs).

6.5. Collected data is to be analyzed and calculations performed as per sections 1 – 5 to establish the engine BSFC.

6.6. The BSFC should be determined at 3 different RPMs and one load to apply the simple quantification method or at 9 RPMs and 3 different loads (3 RPMs per

load) to apply the advanced method. Project proponents are encouraged to use the advanced method wherever feasible in order to fully characterize the fuel consumption of the unmodified engine.

6.7. A table of relevant values should be prepared to document the Pre-Audit results as per the sample table in Appendix C-2.

7. Post-Audit

7.1. A Post-Audit of the engine and compressor (or other load) must be completed after the engine management system has been commissioned in order to compare the fuel consumption of the engine before and after the engine modification.

7.2. If the engine utilizes vent gases as a fuel source (e.g. if a REM Slipstream™ unit or other vent gas capture system has been connected to the engine as a fuel source) then the vent gas fuel source must be turned off or disconnected for the duration of the Post Audit. Fuel consumption measurements will be recorded at three different engine speeds.

7.3. The air fuel ratio and ignition advance should be recorded during the Post-Audit.

7.4. The Recip Trap will be utilized to measure compressor load as the preferred data source. If the compressor does not have pressure access ports, data should be collected to utilize an engineering calculation method to determine load. If the project configuration does not include a compressor, other industry standards may be used to determine loads. Data will be collected at three different engine speeds (RPMs).

7.5. Collected data will be analyzed and calculations performed as per sections 1 – 5 to establish engine BSFC.

7.6. The BSFC should be determined at the same 3 RPMs and the same load as in the Pre-Audit to apply the simple quantification method or at the same 9 RPMs and same 3 different loads (3 RPMs per load) to apply the advanced method. Project proponents are encouraged to use the advanced method wherever feasible in order to fully characterize the fuel consumption of the engine after the installation of the engine management system.

7.7. A table of relevant values should be prepared to document the Pre-Audit results as per the sample table in Appendix C-2.

7.8. If the Pre-Audit and Post-Audit measurements for BSFC are made with brake loads greater than 5% different, refer to Appendix C-1 for a method to normalize the engine efficiency improvement. If the Pre-Audit and Post-Audit loads are less than 5% different proceed to Step 8 to calculate the fractional fuel savings.

8. Fractional Change in Fuel Consumption (Pre-Audit to Post-Audit Conditions)

8.1. Calculate the Fractional Change in Fuel Consumption based on the Pre-Audit and Post-Audit measurements at each RPM and load according to the following formula:

$$\text{Fractional Change in Fuel Consumption (at each RPM and Load)} = (BSFC_{\text{Pre-Audit}} - BSFC_{\text{Post-Audit}}) / BSFC_{\text{Post-Audit}}$$

Simple Method: For projects using the simple method, the BSFC is determined for 3 different RPMs and one load. The fractional change in fuel consumption is assumed to be a function of RPM only, provided that the load did not change significantly (>5%) from the Pre-Audit to the Post-Audit. If the load changed more than 5% from the Pre-Audit to the Post-Audit then project proponent must use the normalization approach described in Appendix C-1 to calculate a new $BSFC_{Pre\text{-}Audit}$ based on the Post-Audit load and the parasitic load. The fractional change in fuel consumption in then calculated using the above formula. A sample data set using the simple method (without normalization) is provided below.

Table C.2- Sample Pre-Audit and Post-Audit Data Output

RPM	BSFC (before)	BSFC (after)	Fractional Change[17]
1200	8300	7400	0.122
1000	8150	7250	0.124
800	8000	7100	0.127

Advanced Method: For projects using the advanced method, 3 BSFC values should be determined for each specific RPM to obtain 3 different curves (one curve of 3 load points for each RPM) to demonstrate a full load map of BSFC versus load before and after the engine modification. With the advanced approach the BSFC is a function of both load and RPM and as such a load change of more than 5% is unlikely to impact the accuracy of the predicted $BSFC_{Pre\text{-}Audit}$. Each 3-point curve can be fit with a trend line (e.g. a polynomial type trend line will typically fit a BSFC versus Load curve quite well) using Microsoft Excel, such that BSFC can be expressed as a function of load for a fixed RPM. When the curve is fit with a second order polynomial type of trend line, the $BSFC_{Pre\text{-}Audit}$ can be approximated with a calculated monthly load according to the following equation, where a, b and c are constants already determined using the Pre and Post-Audit data.

$$BSFC = a(Load)^2 + b(Load) + c \qquad \text{(for a fixed RPM)}$$

The use of the advanced method will allow for the BSFC of the unmodified engine to be determined with ease if/when the engine load changes significantly (>5%) as compared to the initial Pre and Post-Audit conditions. The fractional change in fuel consumption is determined for each calculated BSFC measurement using the same equation above.

9. Project Monitoring and Measurement

In the project condition (after the Pre-Audit and Post-Audit have been completed) a variety of parameters must be monitored to collect the necessary data to quantify GHG reductions associated with the project activity. The project proponent should also refer to Table 2.5 to determine required data and data collection frequencies for the relevant parameters.

[17] Fractional change = $(BSFC_{Pre\text{-}Audit} - BSFC_{Post\text{-}Audit}) / BSFC_{Post\text{-}Audit}$

Data to be collected includes the following:

9.1. Collect Fuel Gas and Vent Gas (if applicable) mass flow rates into the engine (continuously) and aggregate data on a monthly basis.

9.2. Conduct gas analyses for Fuel Gas and Vent Gas streams to obtain lower heating values, gas densities and gas molar compositions (as required).

9.3. Record the average RPMs on a quarterly basis for the engine. For engines known to operate with variable engine speeds, monthly average RPMs should be used.

9.4. Determine the engine load once per month (this will account for every time load changes occur, e.g. when new wells are tied into a gathering system) using an accepted engineering calculation based on compressor suction and discharge pressures, compression ratio, suction and discharge temperatures, gas throughput etc. (or other appropriate method for generators, pumps or other equipment). Alternatively, the fuel index may be used to estimate load if the frequency of data collection is greater than the above minimum requirement of monthly load measurements. In many cases engine loading will change slowly over time and determination of the load once per month is reasonable.

9.5. The project proponent should ensure that any changes to the air-fuel ratio are tracked annually as this engine parameter may impact the fractional change in fuel consumption. It is recommended that the project proponent measure the air manifold pressure and temperature on a regular basis to estimate the air fuel ratio. In the event that the air-fuel ratio has been changed materially from the Post-Audit conditions, it will be up to the third party verifier to use his/her professional opinion to assess the materiality of the impact on the fuel savings claimed by the project proponent.

Table C.3, below, provides a summary of the minimum monitoring requirements for the project condition.

Table C.3- Minimum Monitoring Requirements

Parameter	Units	Minimum Frequency of Measurement
Fuel Gas/ Vent Gas Flow Rates	kg/h	Continuous
Fuel Gas/ Vent Gas Compositions	mole fraction	Annual
Fuel Gas/ Vent Gas Lower Heating Values	GJ/m^3	Annual
Engine Speeds	RPMs	Monthly
Load	Hp, kW	Monthly
Air-Fuel Ratio (λ)	-	Annual (or at verification)

Project proponents should refer to Appendix C-3 for a sample gas analysis and calculation methodologies for determining gas densities and lower heating values. Appendix C-4 also provides additional guidance on monitoring equipment and calibration procedures.

10. Calculation of the Fractional Change in Fuel Consumption (Actual Conditions)

10.1. Simple Method:

If the calculated load in the project condition (as determined under 9.4) does not differ more than 5% from the Pre and Post-Audit measurements, then the fractional change in fuel consumption can be calculated at the specific monthly average RPM using linear interpolation or a least squares best fit of the Pre and Post-Audit data.

If the load has changed more than 5% during monitoring in the project condition, then the $BSFC_{Pre\text{-}Audit}$ should be re-calculated according to the normalization method in Appendix C-1. The $BSFC_{Post\text{-}Audit}$ is also replaced with a calculated value at the new load (as per section 5.) based on metered data from the project condition (fuel flow rate, energy content and load). The fractional change in fuel consumption at the actual conditions is calculated based on the normalized $BSFC_{Pre\text{-}Audit}$ value and the calculated $BSFC_{Post\text{-}Audit}$ value at the new load.

10.2. Advanced Method:

The project proponent should determine the $BSFC_{Pre\text{-}Audit}$ value for each load based on the trend line equation [$BSFC = a(Load)^2 + b(Load) + c$] obtained from the 3-point $BSFC_{Pre\text{-}Audit}$ versus load curve as described in Section 8.

The $BSFC_{Post\text{-}Audit}$ value is calculated based on the measured load, fuel energy flow rate as described in Section 5. The fractional change in fuel consumption for is then calculated for each month using the new BSFC values calculated based on the measured load in the project condition. If the monthly average RPM differs significantly from the Pre and Post-Audit RPM set points, then the project proponent may use linear interpolation or a least squares best fit to determine the fractional change in fuel consumption at the specific RPM based on two data points (RPM and fractional fuel savings) at the same load.

11. Calculate the GHG Emissions for each SS included in Table 2.5

Once the project proponent has determined the fractional change in fuel consumption for each month, the equations in Table 2.5 may be used to determine the GHG emissions for each relevant source and sink.

APPENDICES C-1 to C-4

Additional Guidance for Measurement and Monitoring of Fractional Change in Fuel Consumption

Appendix C-1

A Method of Normalizing and Quantifying Engine Efficiency Improvements

This appendix includes a method to normalize the energy efficiency improvement from the installation of an engine management system where the simple quantification approach is followed. There are two main scenarios when it would be necessary for the project proponent to use this normalization method:

A) If the operating load changed materially (>5%) <u>between</u> the time the Pre-Audit was conducted to the time that the Post-Audit was conducted; or
B) If the simple method was used to conduct the Pre and Post-Audit measurements (1 load point and 3 RPM points) and the operating load changed materially (>5%) at some time <u>after</u> the initial Pre and Post-Audits were conducted (i.e. during regular monitoring in the project condition).

The use of the normalization method follows the same principles for both scenarios.

Introduction

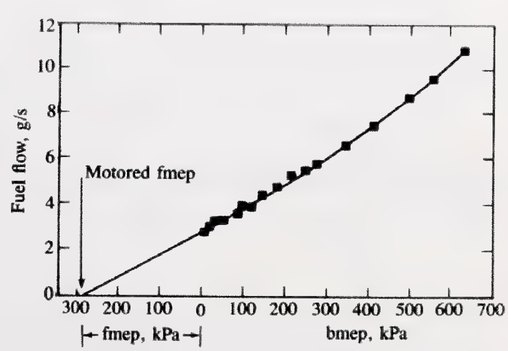
To accurately determine an improvement in fuel efficiency (a reduction in fuel consumption for the actual load) as a result of the installation of an engine management system, the optimum approach is to develop a BSFC map for the full range of engine loads and speeds before and after the installation.

The following description outlines a method by which the BSFC and efficiency changes for a range of operating conditions can be estimated <u>from a more limited set of engine measurements</u>.
It is well known that the BSFC value depends on both engine load and engine speed. To understand how BSFC can be used to determine fuel consumption changes, it is necessary to explain why BSFC changes with engine brake load.

Parasitic Losses

The term parasitic losses refer to the energy expenditures that do not go towards productive work. Some fuel energy is always required to overcome engine friction and other losses.

This is shown clearly by an example Willans plot from page 721 of the book "Internal Combustion Engine Fundamentals" by John Heywood, Professor at MIT shown here. Here the engine fuel flow rate is plotted as a function of Brake Mean Effective Pressure (BMEP). BMEP is a common method of expressing engine brake load. This graph clearly shows that there is a certain fuel flow required at zero brake load in order to keep the engine turning.



Brake mean effective pressure is proportional to engine brake power divided by RPM.

Clearly fuel is consumed even with BMEP equal to zero (e.g. zero brake load). Extrapolation to zero fuel flow shows the Frictional Mean Effective Pressure (FMEP) (*frictional MEP*) or parasitic load.

Frictional mean effective pressure is a measure of the mean effective pressure (MEP) used to overcome friction and other losses in the engine. Other studies for spark ignited engines reported by Heywood show that total frictional MEP, which consists of rubbing friction MEP and pumping MEP, is approximately constant as a function of BMEP. This means that the parasitic load is approximately constant over a range of engine loads.

The assumption that the parasitic load is approximately constant over a certain range of engine loads allows for estimation of the BSFC as discussed below.

BSFC Estimation

Brake specific fuel consumption depends on how much of the engine power is delivered to the load compared to how much is expended in overcoming engine friction at that specific RPM.

Based on the definition of BSFC and the assumption that the same degree of fuel combustion occurs at all loads, the $BSFC_a$ at a load L_a can be expressed by the following formula:

$$BSFC_a = BSFC_r * (1 + P(L_a)/L_a)/(1 + P(L_r)/L_r)$$

Where $BSFC_r$ is a reference BSFC for the rated load at the specified rpm
L_a is the current engine load
L_r is the rated load at which the reference BSFC was measured
$P(L_a)$ is the parasitic load at load L at the specified rpm
$P(L_r)$ is the parasitic load at reference load L at the specified rpm

If the parasitic load P(L) has in fact little or no dependence on load[18], the above expression can be simplified to:

$$BSFC_a = BSFC_r * (1 + P/L_a)/(1 + P/L_r) \text{ with P as a constant for a specific rpm}$$

For example, if the reference $BSFC_r$ is 7600 BTU/BHP-h at a load of 1232 HP, then with a parasitic load of 195 HP, the BSFC at the desired brake load of 1000 HP would be

$$BSFC = 7600 *(1 + 195/1000)/(1 + 195/1232) = 7841 \text{ BTU/BHP-h}$$

Clearly, with a reference BSFC and a parasitic load, a curve can be generated for the BSFC as a function of brake power.

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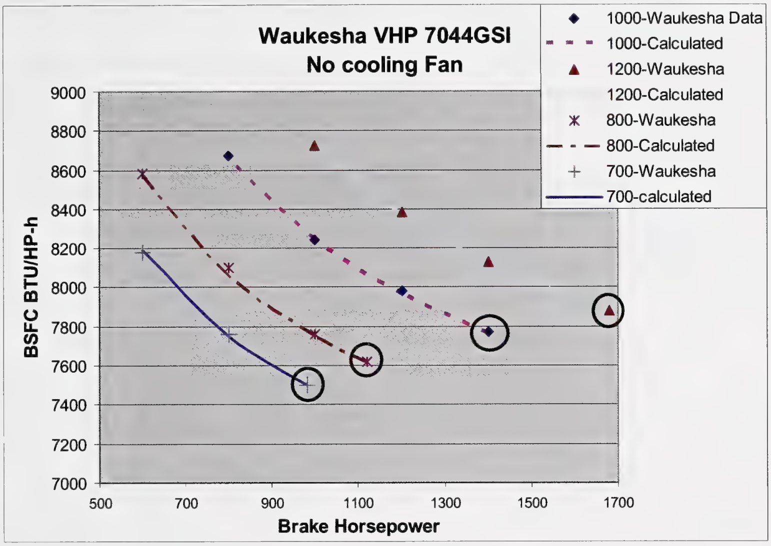
[18] The assumption that P (L) does not depend on load is often not true for large changes in load for all engine configurations. Conservative practice is to limit this assumption for engine torque (Load/rpm) or fuel flow/RPM changes of no more than ± 25%.

This has been done below to replicate the published Waukesha 7044GSI BSFC Graph — no cooling fan.

Figure C-1.1 Normalization Curve for Waukesha VHP 7044GSI



The markers show the values extracted from the published graphs and the markers within the circles show the reference BSFC for each engine speed. The solid lines show the calculated BSFC values. Note that the calculated curves match the markers from the Waukesha BSFC graph[19].

Table C-1.1: Data Used to Create Figure C-1.1

RPM	BSFCr BTU/HP-h	Parasitic Load HP	Parasitic %[20]
1200	7880	312	18.6
1000	7770	252	18
800	7620	190	17
600	7500	167	17

Table C-1.2: Typical Auxiliary Loads

Load Type	Auxiliary %[21]
Generator	2
Compressor	3 to 4

Depending on the load type, an additional amount, the Auxiliary percentage, should be added to provide a total parasitic percentage.

[19] Waukesha Reference curve C278-12
[20] The Parasitic % is the Parasitic Load / Rated Load at the specified rpm.
[21] CAPP – Fuel Gas Best Management Practices – Efficient Use of Fuel Gas in Engines – Appendix A

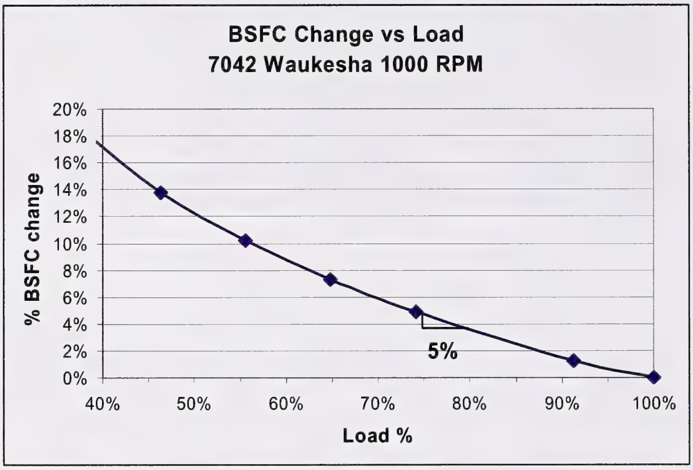
Calculation of Engine Performance Improvement

Because the BSFC is a function of engine load, a comparison of Pre and Post-Audit measurements made at significantly different loads makes a correct determination of the change in BSFC impossible. Hence a load normalization method is required. Because the BSFC is also dependent on engine RPM, the Pre and Post-Audit measurements MUST be made at the same RPMs.

Direct Comparison

If the Pre-Audit and Post-Audit measurements for BSFC are made with brake loads less than 5% different, then a fractional change in BSFC can be calculated with no more than 2% error due to the load difference as shown by the example here.

Figure C-1.2 Change in BSFC versus Engine Load



Normalization of Pre-Audit and Post-Audit Values

If the Pre and Post-Audit measurements are made for loads greater than 5% (of rated load) different, then the load normalization process described below should be used. While large load differences between Pre and Post-Audit measurements are possible, a reasonable rule of thumb should limit the load differences to 25% to use the normalization method.

Initially during the Pre-Audit the BSFC is determined by a measurement of fuel flow, fuel heating value and engine load at several engine operating speeds. By knowing the load and the RPM at which the BSFC is determined and specifying a parasitic load, P, for the engine, a reference load $BSFC_r$ can be determined for the selected operating speeds by inverting the previous formula for BSFC to that below.

$$BSFC_{r1} = BSFC_{m1} * (1 + P/L_r)/(1 + P/L_{m1})$$

Where,

$BSFC_{m1}$ and L_{m1} are the measured values and $BSFC_{r1}$ is the reference BSFC at the rated load.

After the installation of the engine management system the same fuel gas mass flow, fuel heating value and engine load measurements are made for the selected operating speeds in the Post Audit to determine $BSFC_{m2}$ using the same value for P.

$$BSFC_{r2} = BSFC_{m2} * (1 + P/L_r)/(1 + P/L_{m2})$$

For the purposes of normalizing the BSFC, approximate parasitic percentages (engine plus auxiliaries) are estimated as shown below. Typical BSFC curves for the engines without auxiliaries are shown in the CAPP reference.[22]

Table C-1.3: Engine Classifications and Normal Parasitic Percentages

Engine type[23]	Examples	Engine Parasitic %	Total Parasitic% Generator Loads	Total Parasitic% Compressor Loads
Medium NA Stoichiometric	Waukesha VGF Series; Cat 3300, 3400 series	35	37	38.5
Large NA Stoichiometric	Waukesha VHP series. Cat 3500 Series	31	33	34.5
Medium TC Stoichiometric	Waukesha VGF series. Cat 3300, 3400 Series	21	23	24.5
Large TC Stoichiometric	Waukesha VHP GSI series. Cat 3500 series	17.5	19.5	21
Large TC Lean	Waukesha VHP-GL Series. Cat 3500 LE	14	16	17.5

Once the normalization has been completed, the result is a table showing before and after BSFC values for the selected RPM values such as is shown below in Table C-1.4. From the before (Pre-Audit) and after (Post-Audit) BSFC values a fractional change can be calculated. If a direct comparison is used (load difference < 5%) the actual BSFC values can be used. If normalization is required, the reference BSFCs are to be used.

Table C-1.4: Sample Values for Fractional Change in Fuel Consumption

RPM	BSFC (before)	BSFC (after)	Fractional Change[24]
1200	8300	7400	0.122
1000	8150	7250	0.124
800	8000	7100	0.127

Normalization of BSFC Values Due to Load Changes After Pre and Post-Audits

[22] CAPP – Fuel Gas Best Management Practices – Efficient Use of Fuel Gas in Engines – Appendix A
[23] NA = Naturally Aspirated; TC = Turbo-Charged
[24] Fractional change = $(BSFC_{\text{Pre-Audit}} - BSFC_{\text{Post-Audit}})/BSFC_{\text{Post-Audit}}$

If the simple quantification approach was followed to determine the Pre and Post-Audit BSFCs at a single load point and three different RPMs, then a significant load change (>5%) during the project condition would impact the validity of the calculated fuel savings. As such the recommended approach is to use the same normalization method, described above, to normalize the original BSFC value obtained during the Pre-Audit to obtain a reference BSFC at the measured load in the project condition as shown below.

$$BSFC_{\text{Pre-Audit Normalized}} = BSFC_{\text{Pre-Audit1}} * (1 + P/L_m)/(1 + P/L_{\text{Pre-Audit1}})$$

Where the $BSFC_{\text{Pre-Audit1}}$ and $L_{\text{Pre-Audit1}}$ are the measured values from the original Pre-Audit and $BSFC_{\text{Pre-Audit Normalized}}$ is the reference BSFC at the actual measured load (L_m) in the project condition. The $BSFC_{\text{Pre-Audit}}$ is then replaced by the $BSFC_{\text{Pre-Audit Normalized}}$.

The $BSFC_{\text{Post-Audit}}$ is replaced with the actual BSFC determined from the measured load, fuel flow rate and energy content.

The fractional change in fuel consumption is then equal to the difference between the $BSFC_{\text{Pre-Audit Normalized}}$ and the BSFC at the measured load all divided by the actual BSFC.

Calculation of Accumulated GHG Reductions

The comparison of the BSFC before and the BSFC after can show a fractional difference in BSFC by the implementation of the engine management system that is independent of the measured load.

Linear interpolation/extrapolation or a least squares fit can be used to determine the fractional change in fuel consumption as a function of the operating RPM.

The change in fuel consumption as a result of the implementation of the engine management system can be determined by multiplying the fractional change in fuel consumption (at the specific RPM and load) times the metered fuel flow into the operating engine in the project condition. The accumulated fuel reduction is the summation of the fuel savings from each month.

The greenhouse gas reduction can then be calculated from the fuel carbon content and the accumulated fuel reduction as outlined in Table 2.5.

Notes and Comments

1. Clearly the best way to calculate fuel savings and therefore GHG reductions is to perform a comprehensive map of engine fuel consumption for a series of loads and speeds both before and after the installation of an engine management system.
2. The fractional change may be determined without BSFC normalization if the Pre-Audit and Post-Audit engine loads differ by less than +/- 5%.
3. To determine the change in fuel consumption accurately, the measurements must be made carefully and consistently.

4. If there are changes to the engine between the Pre and Post-Audit measurements (e.g. overhaul, fan changes etc.), these should be noted.

Appendix C-2

Sample Data Collection for BSFC Determination

This Appendix provides a summary of relevant data collected for the documentation of engine fuel consumption audits conducted before and after the installation of an engine management system. The sample data, below, provides an overview of relevant measurements to be made by the project proponent or other party before and after the engine management system has been installed. Note that some of the parameters shown in Table C-2.1 may not be used directly in the quantification equations and are shown for information purposes only. A sample equipment calibration table is also provided.

Table C-2.1 Sample Pre and Post-Audit Analysis

Parameter	Pre-Audit	Post-Audit	% Reduction (Fractional Change)
Engine speed [rpm]	1200	1200	
Brake horsepower [bhp]	493	498	
Engine torque load [%]	70%	68%	
NO_x rate [g/bhp-hr]	-	-	
CO concentration [g/bhp-hr]	-	-	
CO_2 concentration [g/bhp-hr]	-	-	
Unburned HC [% Volume]	-	-	
O_2 concentration [%]	-	-	
Ignition Angle	-	-	
Air Fuel Ratio- Lambda [λ]	1.05	1.42	
Average cylinder temperature [°C]	-	-	
Mass fuel flow [kg/hr]	91.8	84.0	
Volumetric flow [e^3m^3/day]	3.138	2.871	
Brake Specific Fuel Consumption BSFC [btu/bhp-hr]	8082	7313	10.5% (0.105)

Clarifications

1. Compressor indicated horsepower was calculated using a static compressor horsepower program plus Recip Trap test results. The #3 cylinder was not equipped with test ports, so horsepower for that cylinder was calculated. All other cylinders were measured using the Recip Trap analyzer.
2. Measured compressor indicated horsepower is adjusted by applying a 5% friction factor.
3. Fuel mass flow was measured with a Fisher-Rosemount Micro Motion meter.
4. Fuel gas analysis provided by site.
5. Lambda is calculated from the measured oxygen percentage in the engine exhaust stream.

6. NO_x Emissions analysis: EPA Method 19. Oxygen (O_2) concentrations and appropriate F factors (ratios of combustion gas volumes to heat inputs) are used to calculate pollutant emissions rates from pollutant concentrations. CO and CO_2 emissions rates have been included using the same methodology as EPA Method 19 using calculated conversion coefficients.
7. Measurements have been made on a dry basis (i.e. water vapour has been removed using portable analyzers).
8. Unburned hydrocarbon measurement is not valid below 4% O_2.
9. BSFC fractional change = $(BSFC_{pre\text{-}audit} - BSFC_{post\text{-}audit}) / BSFC_{post\text{-}audit}$

Table C-2.2 Sample Equipment Calibration Record Table

Device	Manufacturer	Model Number	Serial Number	Required Calibration Frequency	Last Calibration Date
Recip-Trap Engine Analyzer					
Fuel flow meter					
Gas analyzer					
Stage 1 suction pressure transmitter/gauge					
Stage 1 discharge pressure transmitter/gauge					
Stage 2 suction pressure transmitter/gauge					
Stage 2 discharge pressure transmitter/gauge					
Stage 3 suction pressure transmitter/gauge					
Stage 3 discharge pressure transmitter/gauge					

Appendix C-3

Sample Fuel Gas Analysis

The following table outlines a procedure to determine the density of the fuel gas or vent gas stream combusted in an engine based on a laboratory gas analysis. This procedure may be used to calculate project specific gas densities and fuel gas lower heating values for the quantification of SSRs in Table 2.5. This table and sample data has been kindly provided by REM Technology Inc as a reference tool for project proponents.

Table C-3.1 Sample Gas Analysis[25]

Calculation of GHV and LHV - S tandard conditions 15C, 101.3 kPa (59 F, 14.69 psi)

Component	Formula	Volume (molar) Fr	GHV BTU/scf	LHV BTU/scf	LHV Contribution	GHV Contribution	Compr Factor	Compr Contrib	Density at 15 C kg/m3	Fraction
Methane	CH_4	0.8505	1010	909.4	773.4	859.0	0.0116	0.0099	0.678469	0.577038
Ethane	C_2H_6	0.1016	1758	1618.7	164.5	178.6	0.0239	0.0024	1.270838	0.129117
Ethene	C_2H_4		1604	1499	0.0	0.0	0.02	0.0000	1.270838	0
Propane	C_3H_8	0.0229	2452	2314.9	53.0	56.2	0.0344	0.0008	1.864898	0.042706
Propene	C_3H_6		2340	2182	0.0	0.0	0.033	0.0000	1.864898	0
Iso-Butane	C_4H_{10}	0.0018	3256	3000.4	5.4	5.9	0.0458	0.0001	2.458113	0.004425
N-Butane	C_4H_{10}	0.0024	3266	3010.8	7.2	7.8	0.0478	0.0001	2.458113	0.005899
Iso-Pentane	C_5H_{12}	0.0003	4009	3699	1.1	1.2	0.0581	0.0000	3.051327	0.000915
N-Pentane	C_5H_{12}	0.0002	4018	3703.9	0.7	0.8	0.0631	0.0000	3.051327	0.00061
N-Hexane	C_6H_{14}	0.0001	4770	4403.9	0.4	0.5	0.0802	0.0000	3.644542	0.000364
N-Heptane	C_7H_{16}	0	5519	5100.3	0.0	0.0	0.0904	0.0000	3.644542	0
Carbon Monoxide	CO		320.5	320.5	0.0	0.0	0.005	0.0000	1.188326	0
Hydrogen	H_2		325.7	273.9	0.0	0.0	0	0.0000	0.085254	0
Hydrogen sulphide	H_2S		633.7	586.8	0.0	0.0	0.0253	0.0000	1.441366	0
Nitrogen	N_2	0.0117					0.0044	0.0001	1.184726	0.013861
Oxygen	O_2						0.0073	0.0000	1.354573	0
Helium	He	0.0004					0	0.0000	0.169275	6.77E-05
Argon	Ar						0.0071	0.0000	1.691083	0
Carbon dioxide	CO_2	0.0081					0.0197	0.0002	1.860386	0.015069
Water vapour	H_2O						0.0623	0.0000	0.76	0
Sums		1.000			1005.8	1110.0		0.0135		0.790073
							Z =	0.9973		

GHV	LHV	SLHV		
1113	1009	991	BTU/scf	60 F, 14.69 psi
41.41	37.52	36.87	MJ/m³	15C, 101.3 kPa

LHV/GHV	0.906			
Density	0.790	kg/m³	0.0493	lb/ft³
SG	0.644			

25 Provided by REM Technology Inc.

Appendix C-4
Recommended Measurement Equipment and Calibration Procedures

This appendix illustrates sample measurement equipment and calibration approaches relevant for project proponents using this protocol. It is included in the protocol in order to provide the project proponent with additional best practice guidance following the main procedure for determination of the BSFC and fractional change in fuel consumption described in this appendix. It is however, recognized that project proponents may not install these same makes/models of equipment for data monitoring and therefore this appendix should be used as a guide and additional guidance should be sought from the specific equipment manufacturer as to the best practices for equipment maintenance and calibration.

FOX
THERMAL INSTRUMENTS, INC.

July 2, 2008

Brian Murray
Power Ignition and Controls

Dear Brian,

Confirming our telephone conversation. Fox recommends that our Flowmeter products be returned to Fox for recalibration every two years. Normal turn around time is five to ten working days. All products returned to Fox must be cleaned to remove foreign material and contaminates. Wiping with alcohol generally meets this requirement. Please call our customer service department for a Return Material Authorization (RMA) number before returning products to Fox.

Thank you for your continued interest in our products. Please contact me if you have questions.

Sincerely,

Rich Cada
VP Sales & Marketing

399 Reservation Rd. x Marina, CA 93933 x USA
Phone (831) 384-4300 x Fax (831) 384-4312 x E-mail: sales@foxthermalinstruments.com
www.foxthermalinstruments.com

FOX
THERMAL INSTRUMENTS, INC.

July 8, 2008

Brian Murray
Power Ignition and Controls

Dear Brian,

Confirming our telephone conversion today, Fox Thermal Instruments performs factory calibrations on all flowmeters we sell. Our flow labs use primary or transfer standards and are traceable to NIST Standards in accordance with Mil-Std-45662A. We send our standards to an independent calibration lab on an annual basis. Attached is a sample of our calibration certificate.

Please contact me if you require additional information.

Sincerely,

Rich Cada
VP Sales & Marketing

399 Reservation Rd. x Marina, CA 93933 x USA
Phone (831) 384-4300 x Fax (831) 384-4312 x E-mail: sales@foxthermalinstruments.com
www.foxthermalinstruments.com

Configuration and Use Manual
P/N 20001715, Rev. B
September 2006

Micro Motion®
Series 1000 and
Series 2000 Transmitters

Configuration and Use Manual

- Model 1500 with analog outputs
- Model 1700 with analog outputs
- Model 1700 with intrinsically safe outputs
- Model 2500 with configurable input/outputs
- Model 2700 with analog outputs
- Model 2700 with intrinsically safe outputs
- Model 2700 with configurable input/outputs

Micro Motion

EMERSON.
Process Management

5.5 Zeroing the flowmeter

Zeroing the flowmeter establishes the flowmeter's point of reference when there is no flow. The meter was zeroed at the factory, and should not require a field zero. However, you may wish to perform a field zero to meet local requirements or to confirm the factory zero.

When you zero the flowmeter, you may need to adjust the zero time parameter. *Zero time* is the amount of time the transmitter takes to determine its zero-flow reference point. The default zero time is 20 seconds.

- A *long* zero time may produce a more accurate zero reference but is more likely to result in a zero failure. This is due to the increased possibility of noisy flow, which causes incorrect calibration.
- A *short* zero time is less likely to result in a zero failure but may produce a less accurate zero reference.

For most applications, the default zero time is appropriate.

Note: In some menus, a convergence limit parameter is displayed. Micro Motion recommends that you use the default value for convergence limit.

Note: Do not zero the flowmeter if a high severity alarm is active. Correct the problem, then zero the flowmeter. You may zero the flowmeter if a low severity alarm is active. See Section 7.5 for information on viewing transmitter status and alarms.

If the zero procedure fails, see Section 12.6 for troubleshooting information. Additionally, if you have the enhanced core processor:

- You can restore the factory zero. This procedure returns the zero value to the value obtained at the factory. The factory zero can be restored with ProLink II or the display (if the transmitter has a display).
- If you are using ProLink II to zero the flowmeter, you can also restore the prior zero immediately after zeroing (e.g., an "undo" function), as long as you have not disconnected from the transmitter. Once you have disconnected from the transmitter, you can no longer restore the prior zero.

5.5.1 Preparing for zero

To prepare for the zero procedure:

1. Apply power to the flowmeter. Allow the flowmeter to warm up for approximately 20 minutes.
2. Run the process fluid through the sensor until the sensor temperature reaches the normal process operating temperature.
3. Close the shutoff valve downstream from the sensor.
4. Ensure that the sensor is completely filled with fluid.
5. Ensure that the process flow has completely stopped.

⚠ CAUTION

If fluid is flowing through the sensor, the sensor zero calibration may be inaccurate, resulting in inaccurate process measurement.

To improve the sensor zero calibration and measurement accuracy, ensure that process flow through the sensor has completely stopped.

5.5.2 Zero procedure

To zero the flowmeter, refer to the procedures shown in Figures 5-3 through 5-6. Note the following:

- The zero button is available only on Model 1500 or Model 2500 transmitters. It is located on the front panel of the transmitter. To press the zero button, use a fine-pointed object that will fit into the opening (0.14 in [3.5 mm]). Hold the button down until the status LED begins to flash yellow.
- If the off-line menu has been disabled, you will not be able to zero the transmitter with the display.
- You cannot change the zero time with the zero button or the display. If you need to change the zero time, you must use the Communicator or ProLink II.

Figure 5-3 **Zero button – Flowmeter zero procedure**

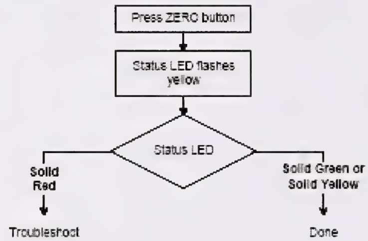
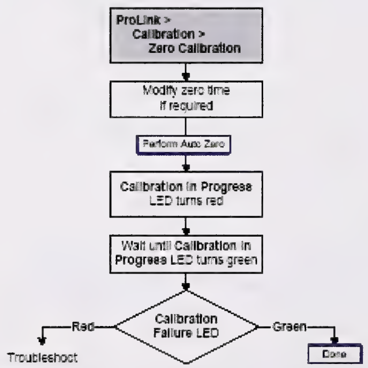
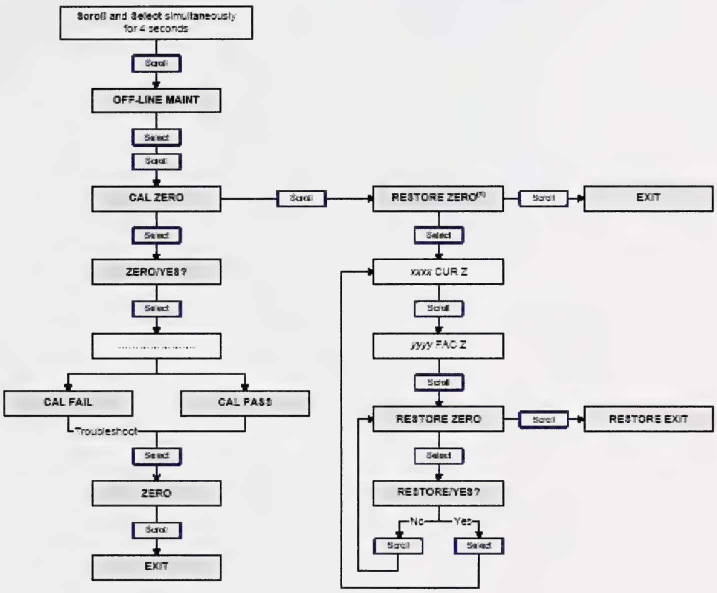


Figure 5-4 **ProLink II – Flowmeter zero procedure**



Flowmeter Startup

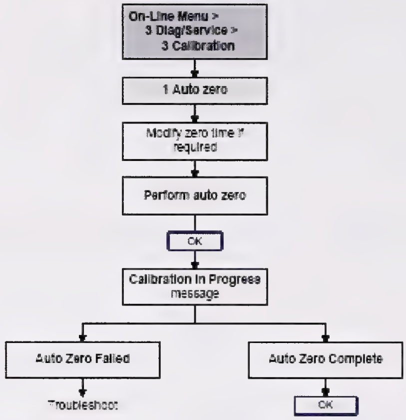
Figure 5-5 **Display menu – Flowmeter zero procedure**



(1) Available only on systems with the enhanced core processor.

Flowmeter Startup

Figure 5-6 **Communicator – Flowmeter zero procedure**



Instruction Manual
P/N 3100572, Rev. E
March 2004

Micro Motion®
Model IFT9701 Transmitter with Optional Display

Instruction Manual

Micro Motion

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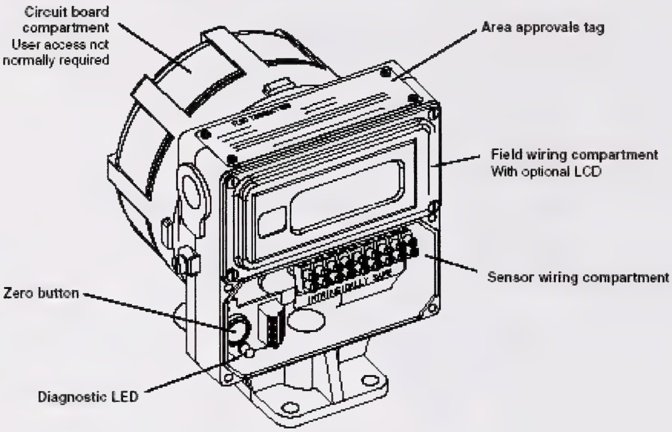
Process Management

Flowmeter Startup *continued*

Figure 5-1 Location of LED, zero button, and LCD



5.5 Flowmeter zeroing

After the flowmeter has been fully installed, you must perform the zeroing procedure.

- To perform the zeroing procedure using the flowmeter zero button, see the following instructions.
- To use a HART Communicator for zeroing, see Chapter 6.
- To use ProLink II software for zeroing, see Chapter 7.

5.5.1 Zeroing procedure

1. Prepare the flowmeter for zeroing:
   a. Install the flowmeter according to the instructions in this manual.
   b. Apply power to the meter, then allow it to warm up for at least 30 minutes.
   c. Run the process fluid to be measured through the flowmeter until the meter temperature approximates the normal process operating temperature.
   d. Ensure that the sensor is completely filled with fluid.
2. Close the shutoff valve downstream from the meter.

⚠ CAUTION

Flow through the flowmeter during flowmeter zeroing will result in an inaccurate zero setting.

Make sure fluid flow through the flowmeter is *completely* stopped during flowmeter zeroing.

Flowmeter Startup *continued*

3. Fill the flowmeter *completely* with the process fluid under normal process conditions of temperature, density, pressure, etc., and ensure zero flow through the flowmeter.
4. Make sure flow through the meter is *completely* stopped, then press and hold the zero button until the LED remains on continuously. See Figure 5-1.

To end the zero operation before its completion, cycle power to the flowmeter.

The LED remains on continuously and the optional display reads "ZERO0" for up to one minute during zeroing. After the zeroing procedure has been completed, the LED again blinks ON once per second to indicate normal operation, and the optional display again indicates the flow rate.

5.5.2 Diagnosing zero failure

If zeroing fails:

- The LED blinks ON four times per second.
- The flowmeter produces fault outputs.
- The blinking message "ELEC0" appears in the optional display.

An error condition could be caused by any of the following:

- Flow of fluid during flowmeter zeroing
- Partially empty flow tubes
- An improperly mounted flowmeter

To clear a zeroing error, cycle power, then re-zero the flowmeter after correcting the problem, or abort the procedure by cycling power to the flowmeter.

5.6 Configuration, calibration, and characterization

The following information explains the difference between configuration, calibration, and characterization. Certain parameters might require *configuration* even when *calibration* is not necessary.

Configuration parameters include such items as flow cutoff and damping values, flow direction, and milliamp output scaling. If requested at time of order, the meter is configured at the factory according to customer specifications.

Calibration parameters include the calibration factors for flow, density, and temperature. Field calibration is optional.

Characterization is the process of using a communication device to enter calibration factors for flow, density, and temperature directly into flowmeter memory, instead of performing field calibration procedures. Calibration factors can be found on the flowmeter serial number tag and on the certificate that is shipped with the meter.

To configure, calibrate, or characterize the flowmeter:

- Using a HART Communicator, see Chapter 6
- Using ProLink II software, see Chapter 7

You can also use AMS software to configure and characterize Micro Motion flowmeters. For instructions on using AMS software, refer to the AMS on-line help.

DYNALCO

July 8, 2008

Mr. Brian Murray
Power Ignition & Controls
9604 - 41 Ave
Edmonton, Alberta T6E 6G9
Canada

Re: SS2200-541

Dear Brian,

We recommend that the Dynalco Recip-Trap models RT9240 & RT9260 portable machinery analyzers be calibrated on an annual basis.

Please feel free to contact me at any time if you need further assistance.

Best regards,

Bruce Raham

Applications Engineer
Ph (954) 739-4300 X201
Fax (954) 486-4968
Dynalco
3690 NW 53rd Street
Fort Lauderdale, FL 33309
braham@dynalco.com

www.dynalco.com

DYNALCO

CERTIFICATE OF CALIBRATION

MANUFACTURER	:	DYNALCO CONTROLS
SPECIFICATIONS	:	Manufacturer's Specifications
MODEL NO.	:	RT9240ECR
SERIAL NO.	:	RTV-XXX
DATE	:	6/20/08
CERTIFICATE NO.	:	

The accuracy and calibration of this instrument is traceable to the National Institute of Standards and Technology through certified standards maintained by Dynalco Controls and is guaranteed to meet published specifications.

AUTHORIZED SIGNATURE

3690 N.W. 53rd Street, Fort Lauderdale, FL 33309 U.S.A.
Ph (954) 739-4300 • Fax (954) 486-4968 • www.dynalco.com

APPENDIX D

Relevant Emission Factors[26]

[26] Source: Environment Canada (*subject to updates*)

Table D1: Emission Intensity of Fuel Extraction and Production (Diesel, Natural Gas, and Gasoline)

Diesel		
Production		
Emissions Factor (CO_2)	0.138	kg CO_2 per Litre
Emissions Factor (CH_4)	0.0109	kg CH_4 per Litre
Emissions Factor (N_2O)	0.000004	kg N_2O per Litre
Natural Gas		
Extraction		
Emissions Factor (CO_2)	0.043	kg CO_2 per m^3
Emissions Factor (CH_4)	0.0023	kg CH_4 per m^3
Emissions Factor (N_2O)	0.000004	kg N_2O per m^3
Processing		
Emissions Factor (CO_2)	0.090	kg CO_2 per m^3
Emissions Factor (CH_4)	0.0003	kg CH_4 per m^3
Emissions Factor (N_2O)	0.000003	kg N_2O per m^3
Gasoline		
Production		
Emissions Factor (CO_2)	0.138	kg CO_2 per Litre
Emissions Factor (CH_4)	0.0109	kg CH_4 per Litre
Emissions Factor (N_2O)	0.000004	kg N_2O per Litre

Table D2: Combustion Emission Factors for Natural Gas and NGL's

Source	Emission Factors		
	CO_2	**CH_4**	**N_2O**
	g/m^3	**g/m^3**	**g/m^3**
Natural Gas			
Electric Utilities	1891	0.49	0.049
Industrial	1891	0.037	0.033
Producer Consumption	2389	6.5	0.06
Pipelines	1891	1.9	0.05
Cement	1891	0.037	0.034
Manufacturing Industries	1891	0.037	0.033
Residential, Construction, Commercial/Institutional, Agriculture	1891	0.037	0.035
	g/L	**g/L**	**g/L**
Propane			
Residential	1510	0.027	0.108
All Other Uses	1510	0.024	0.108
Ethane	976	N/A	N/A
Butane	1730	0.024	0.108

Table D3: Emission Factors for Refined Petroleum Products

Source	Emission Factors (g/L)		
	CO_2	CH_4	N_2O
Light Fuel Oil			
Electric Utilities	2830	0.18	0.031
Industrial	2830	0.006	0.031
Producer Consumption	2830	0.006	0.031
Residential	2830	0.026	0.006
Forestry, Construction, Public Administration, and Commercial/Institutional	2830	0.026	0.031
Heavy Fuel Oil			
Electric Utilities	3080	0.034	0.064
Industrial	3080	0.12	0.064
Producer Consumption	3080	0.12	0.064
Residential, Forestry, Construction, Public Administration, and Commercial/Institutional	3080	0.057	0.064
Kerosene			
Electric Utilities	2550	0.006	0.031
Industrial	2550	0.006	0.031
Producer Consumption	2550	0.006	0.031
Residential	2550	0.026	0.006
Forestry, Construction, Public Administration, and Commercial/ Institutional	2550	0.026	0.031
Diesel	2730	0.133	0.4
Gasoline (Light Duty Trucks)	2360	0.13	0.25

Development of a site specific CO_2 emission factor for natural gas

The development of a site specific CO_2 emission factor for natural gas combustion requires a complete gas analysis of the measured mole fractions of each carbon-containing compound in the fuel gas. See Table C-3.1 in Appendix C-3 for a sample fuel gas analysis. The site specific emission factor should be used in place of the default factors whenever complete gas analyses are available.

The calculation of the CO_2 emission factor can be done using the following equation taken from the Canadian Association of Petroleum Producers (CAPP) document "Calculating Greenhouse Gas Emissions" (April 2003):

$$[(a + 2b + 3c + 4d + 5e + f) \times 44.01] / 23.64$$

Where,

The variables "a" through "e" are the mole fractions of each hydrocarbon compound contained in the fuel gas. The "a" would correspond to the mole fraction of methane; "b" would correspond to the mole fraction of ethane etc. The number in front of each letter corresponds to the number of carbon atoms per molecule (i.e. one carbon atom for methane and two for ethane).

The variable "f" is the mole fraction of CO_2 in the gas stream

44.01 = Molecular weight of CO_2 in kg / kmol
23.64 = the volume in m^3 occupied by 1 kmole of gas at 15°C and 101.325 kPa.

APPENDIX E

Specified Gases and Global Warming Potential

Specified Gases and Their Global Warming Potentials

Specified Gas	Chemical Formula	Global Warming Potential (100 year time horizon)
Carbon dioxide	CO_2	1
Methane	CH_4	21
Nitrous oxide	N_2O	310
HFC-23	CHF_3	11700
HFC-32	CH_2F_2	650
HFC-41	CH_3F	150
HFC-43-10mee	$C_5H_2F_{10}$	1300
HFC-125	C_2HF_5	2800
HFC-134	$C_2H_2F_4$	1000
HFC-134a	CH_2FCF_3	1300
HFC-152a	$C_2H_4F_2$	140
HFC-143	$C_2H_3F_3$	300
HFC-143a	$C_2H_3F_3$	3800
HFC-227ea	C_3HF_7	2900
HFC-236fa	$C_3H_2F_6$	6300
HFC-245ca	$C_3H_3F_5$	560
Sulphur hexafluoride	SF_6	23900
Perfluoromethane	CF_4	6500
Perfluoroethane	C_2F_6	9200
Perfluoroproprane	C_3F_8	7000
Perfluorobutane	C_4F_{10}	7000
Perfluorocyclobutane	$c\text{-}C_4F_8$	8700
Perfluoropentane	C_5F_{12}	7500
Perfluorohexane	C_6F_{14}	7400